Canadian Natural

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD NINE MONTH RESULTS
CALGARY, ALBERTA – November 5, 2003 – FOR IMMEDIATE RELEASE

In commenting on third quarter 2003 results, Canadian Natural's Chairman, Allan Markin, stated "This was another quarter of executing our program and delivering results. Our quarterly production was on guidance and when combined with strong commodity prices and lower operating costs, resulted in record cash flow and solid third quarter earnings. Operationally, our Western Canadian and North Sea assets are delivering as expected, and we have made significant progress on our larger, future-growth projects."

"During the quarter we completed the Joint Panel for regulatory approvals on the Horizon Oil Sands Project. Completion of this public hearing positions us to have the required regulatory approvals in place for the project late this year or early next year. We also started our detailed engineering work for the project, which will be complete in 2004, a key consideration for final construction approval by our Board of Directors."

"In Offshore West Africa, we have completed the first phase of the East Espoir project and development of the Baobab Field is underway with development drilling commencing in November."

"We have also finalized our 2004 Budget which results in average organic production growth estimated in excess of 5% and exit volume growth in excess of 10%, despite significant spending on long-lead projects at Baobab and Horizon."

HIGHLIGHTS OF THE THIRD QUARTER

- Record nine month net earnings of $1.2 billion ($8.61 per common share) compared with $0.4 billion ($2.87 per common share) in 2002.
- Record nine month cash flow of $2.4 billion ($18.06 per common share) compared with $1.5 billion ($11.73 per common share) in 2002.
- Record third quarter cash flow of $758 million ($5.62 per common share) compared with $643 million ($4.83 per common share) in the third quarter of 2002 and $762 million ($5.68 per common share) in the previous quarter.
- Third quarter net earnings of $203 million ($1.51 per common share) compared with $117 million ($0.88 per common share) for the third quarter of 2002 and $525 million ($3.91 per common share) in the previous quarter. Adjusted net earnings from operations amounted to $215 million ($1.60 per common share) compared with $164 million ($1.23 per common share) for the third quarter of 2002 and $256 million ($1.91 per common share) in the previous quarter.
- Record third quarter crude oil and NGLs sales of over 247 thousand barrels per day at the mid point of guidance.
- Continued strong natural gas sales of 1,289 million cubic feet per day, at the mid point of guidance and equal to 46% of production.
- Net capital expenditures of $621 million reflected the active heavy crude oil drilling program, facilities work resulting from the winter natural gas drilling program and continued development of international properties. During the quarter, Canadian Natural drilled 385 wells, including 196 shallow natural gas wells.
- Reduced long-term debt by $153 million during the quarter through repayments of $148 million and foreign exchange gains of $5 million resulting from the strengthening of the Canadian dollar. This reduced debt to book capitalization to 33% compared with 46% at year end 2002 and 48% immediately following the acquisition of Rio Alto Exploration Ltd. on July 1, 2002.

- Under its Normal Course Issuer Bid, the Company purchased 1,075,000 of its common shares during the third quarter for a total cost of $58 million (average cost - $54.01/share). As of November 4, 2003, the Company had purchased approximately 2.4 million of its common shares (average cost - $51.29/share) for a total cost of $125 million.
- As expected, crude oil and NGLs production expenses were reduced in each area for total savings of $0.66 per barrel or 6% from the previous quarter.
- Horizon Oil Sands Project Joint Panel for regulatory approvals was held during September with regulatory approvals expected late this year or early next year. Third and final phase of pre-construction engineering, Engineering Design Specification ("EDS"), commenced with completion expected in mid-2004.

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			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Net earnings attributable to common shareholders as reported	**$ 203**	$ 525	$ 117	**$ 1,156**	$ 361
Unrealized foreign exchange (gain) loss [1]	**(9)**	(87)	41	**(192)**	(35)
Unrealized foreign exchange (gain) loss on preferred securities[1]	**-**	(7)	6	**(14)**	-
Effect of statutory tax rate changes on future income tax liabilities[2]	**-**	(247)	-	**(247)**	13
Stock-based compensation expense [3]	**21**	72	-	**93**	-
Reduction in carrying value of foreign assets[4]	**-**	-	-	**-**	30
Adjusted net earnings from operations attributable to common shareholders	**$ 215**	$ 256	$ 164	**$ 796**	$ 369
Per share – basic	**$ 1.60**	$ 1.91	$ 1.23	**$ 5.93**	$ 2.93
– diluted	**$ 1.58**	$ 1.88	$ 1.20	**$ 5.79**	$ 2.83

[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 nine months ended September 30, 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.*

[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 $21 million after taxes ($32 million before taxes) was recognized in the third quarter of 2003.*

[4] *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

Production

Production of both natural gas and crude oil and NGLs were within guidance parameters previously announced. Crude oil and NGLs production for the nine month period ended September 30, 2003 increased approximately 35 mbbls/d or 17% from the previous year. Similarly natural gas production has increased by 120 mmcf/d or 10% from the previous year.

During the third quarter, crude oil and NGLs production increased as a result of the Company's heavy crude oil drilling program in western Canada and the perforation of upper producing zones at the Espoir Field located offshore Côte d'Ivoire. North Sea production increases reflected previous quarter downtime resulting from maintenance work at the Ninian South Platform and the consolidation of interests at the Banff Field.

As expected, natural gas production levels decreased from the second quarter to 1,289 mmcf/d. This reflects the normal production declines on the portion of Canadian Natural's asset base that is suitable for winter-only access. In addition, approximately 11 mmcf/d of Canadian Natural's natural gas production was shut-in during the month of September due to the bitumen conservation measures undertaken by the Energy Utilities Board ("EUB") in Alberta. The Alberta Department of Energy ("ADOE") has recently announced an interim assistance plan under which Alberta crown royalty deferrals are granted at a rate of $0.60/mcf of shut-in production. A long-term assistance plan is still under discussion with the ADOE.

The Company's production composition is as follows:

	Q3 2003		Q2 2003		Q3 2002	
	mboe/d	%	mboe/d	%	mboe/d	%
Natural gas	**214.9**	**46**	220.9	48	237.9	50
Light crude oil and NGLs	**118.9**	**26**	112.0	24	102.8	21
Pelican Lake crude oil	**23.5**	**5**	25.9	6	32.0	7
Primary heavy crude oil	**68.3**	**15**	63.8	14	66.9	14
Thermal heavy crude oil	**36.3**	**8**	38.9	8	40.3	8
Total	**461.9**	**100**	461.5	100	479.9	100

The Company expects production levels in the fourth quarter of 2003 to average 1,255 to 1,280 mmcf/d of natural gas and 240 to 250 mbbls/d of crude oil and NGLs. This results in expected annual 2003 production levels of approximately 1,295 to 1,300 mmcf/d of natural gas (2002 – 1,230 mmcf/d) and approximately 241 to 245 mbbls/d of crude oil and NGLs (2002 – 215 mbbls/d).

DRILLING ACTIVITY (number of wells)

	Nine Months Ended September 30			
	2003		2002	
	Gross	**Net**	Gross	Net
Oil	**390**	**366**	290	253
Natural gas	**616**	**577**	165	150
Dry and abandoned	**44**	**41**	27	23
Subtotal	**1,050**	**984**	482	426
Stratigraphic test/service wells	**378**	**374**	416	408
Total	**1,428**	**1,358**	898	834
Success rate (excluding strat test/service wells)		**96%**		95%

During the third quarter, Canadian Natural drilled 93 net crude oil wells concentrated in the Company's heavy crude oil areas of North Alberta/West Saskatchewan and 278 net natural gas wells. The natural gas wells included 196 shallow wells in South Alberta, which have productive rates from 50 mcf/d to 200 mcf/d, as well as 25 net wells in Northwest Alberta which have productive rates from 400 mcf/d to 5,000 mcf/d. The total success rate for Canadian Natural's drilling program was 97% during the third quarter, excluding injection/stratigraphic test wells.

During the first nine months of the year, the Company has drilled a total of 1,358 wells, up 63% from 2002 levels. In particular, natural gas drilling has increased to almost four times the level of activity experienced last year, while crude oil drilling has increased 45%.

Canadian Natural expects to drill approximately 460 net crude oil and 895 net natural gas wells during 2003, up 74% and 452% from 2002 levels and 99% and 88% from 2001 levels, respectively.

During the first nine months of the year, the Company drilled 374 net stratigraphic test/service wells on the oil sands leases in the Horizon Oil Sands Project and in North Alberta/West Saskatchewan.

Pricing

Product pricing remained strong during the third quarter for both crude oil and natural gas. West Texas Intermediate ("WTI") benchmark pricing was up versus both the previous quarter and last year, while natural gas pricing was slightly below second quarter but significantly higher than the corresponding quarter of last year. Heavy oil price differentials remained tight, largely as a result of lower supply from Venezuela. Canadian Natural expects these heavy oil differentials to widen during the fourth quarter due to normal seasonality. Detailed reviews of benchmark pricing and Canadian Natural's realized prices are available in Management's Discussion and Analysis.

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

The Company utilizes hedges on a portion of its production in an effort to assure operating cash flows are sufficient to cover capital expenditures. Policies now allow for up to 50% of any one commodity to be hedged using cost-less collars for a period not exceeding 12 months, and for up to 25% of production to be hedged beyond 12 months and up to 24 months. The corporate hedging policies are reviewed on a regular basis and this revision reflects the transition of Canadian Natural's project portfolio to longer-term developments. This policy may be reviewed at a future date in anticipation of the significant scope of the Horizon Oil Sands Project. As at November 4, the Company had entered into fourth quarter 2003 commodity hedges covering approximately 1% and 50% of anticipated natural gas production and crude oil production, respectively.

Fourth quarter indicative prices as at November 4, 2003 include a reference WTI price of US$28.78/bbl, and NYMEX natural gas price of US$4.71/mmbtu and a Lloyd Blend heavy oil differential of US$11.48/bbl.

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at September 30, 2003	Drilling Activity nine months ended September 30, 2003
	(thousands of net acres)	(net wells)
Northeast British Columbia	**1,536**	**96**
Northwest Alberta	**1,762**	**78**
North Alberta	**5,680**	**553**
South Alberta	**671**	**281**
Southeast Saskatchewan	**147**	**20**
Horizon Oil Sands Project	**117**	**312**
North Sea	**563**	**15**
Offshore West Africa	**943**	**3**
Total	**11,419**	**1,358**

2004 Budget

Canadian Natural continues its strategy of maintaining a large portfolio of varied projects, which enables the Company over an extended period of time to provide consistent growth in production and high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of project returns, product pricing expectations, and balance in project risks and time horizons. Canadian Natural maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of expenditures in each of its project areas.

Canadian Natural is presently budgeting cash flow from operations in 2004 of $2.4 billion to $2.7 billion. This cash flow is derived from production of 1,320 to 1,395 mmcf/d of natural gas and 247,000 to 272,000 bbls/d of crude oil and NGLs, and applying pricing parameters averaging WTI price of US $26.00/bbl, a Lloyd Blend heavy oil differential of US $8.50/bbl, NYMEX natural gas price of US $5.00/mmbtu and a US $/Cdn $ exchange rate of $0.75.

Based upon the following capital expenditure budget, Canadian Natural expects to incur Canadian current income tax expense in 2004 of $150 to $250 million.

Canadian Natural expects to drill approximately 921 net natural gas wells and 459 net crude oil wells and 321 stratigraphic test/service wells in 2004, the programs for which are further discussed in the applicable area summary.

The budgeted capital expenditures in 2004 are currently expected to be as follows:

($ millions)	2003 Forecast	2004 Budget
North America natural gas	**$ 950**	**$ 928**
North America liquids	**630**	**615**
North Sea liquids	**270**	**340**
Offshore West Africa liquids	**210**	**350**
Property acquisitions and midstream	**325**	**59**
	2,385	**2,292**
Horizon Oil Sands Project(1)	**165**	**200 - 600**
TOTAL	**$ 2,550**	**$ 2,492 - 2,892**

(1) *Expenditure level is dependent upon timing of regulatory and Board of Director approvals.*

Capital spending in North America will be reduced by $200 million from 2003 spending levels reflecting Canadian Natural's view that property acquisition opportunities will be reduced. Natural gas spending is down reflecting Canadian Natural's significant capital efficiencies achieved during 2003.

The implementation of this capital program will result in Canadian Natural's 2004 North American natural gas exit rates increasing in excess of 8% with average yearly rates increasing by approximately 6%. Overall crude oil and NGLs exit rates will increase in excess of 15% with average rates increasing by approximately 7%.

North American Natural Gas

Canadian Natural's drilling program during the third quarter was highlighted by the summer shallow natural gas program (196 wells) in South Alberta. Shallow natural gas programs in South Alberta, while integral to the Company's ongoing success are not sufficient to offset normal production declines from winter-only access fields in other Core Regions and the declines experienced at Ladyfern; hence the Company experienced lower third quarter volumes when compared with second quarter natural gas production levels.

Canadian Natural continually focuses on reducing costs by achieving capital efficiency in its operations. In Northwest Alberta Canadian Natural has achieved significant cost reductions in drilling and completions. On the majority of properties in the Cardium based southern portion, drilling costs (a significant component of finding and development costs) were reduced by at least 40% and completion costs by 50% from those experienced in 2002. These cost reductions were achieved applying the most appropriate technical applications to maximize well reserves and rate. Canadian Natural is ramping up development of this area and expects to drill a further 10-15 wells in 2003 and 174 wells during 2004.

The 2004 natural gas program will be highlighted by expanded drilling programs in the Northwest Alberta and Northeast British Columbia core regions as shown below.

(number of wells)	**2003 Forecast**	**2004 Budget**
Northeast British Columbia	**108**	**176**
Northwest Alberta	**112**	**165**
North Alberta	**223**	**174**
South Alberta	**479**	**406**
TOTAL	**922**	**921**

Northeast British Columbia drilling reflects an increased Helmet drilling program, as well as a shallow natural gas drilling program in the Fort St. John block 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 resources. As has been previously articulated, these reserves will be developed as heavy crude oil markets permit. Given the normal production profile of new heavy crude oil wells, third quarter production increases reflect the drilling program completed by the Company over the first nine months of the year. Canadian Natural's drilling program during the third quarter was concentrated on 63 heavy crude oil wells in North Alberta, for a total of 257 wells during the first nine months of the year.

As an integral part of the long-term heavy crude oil strategy mentioned above, the Company's Primrose drilling program continues on budget with 21 new thermal wells already having been drilled during 2003. A further 22 wells will be drilled during the fourth quarter of 2003, with steaming to commence late in 2003. First production from these new wells will commence in mid-2004.

In 2004, Canadian Natural expects to grow its North American volumes by approximately 3 to 7%, largely through continued drilling of conventional heavy crude oil wells and through production increases from the previously mentioned Primrose drilling program. The 2004 drilling program consists of 180 conventional heavy wells, 94 thermal heavy wells, 62 light crude oil wells and 96 Pelican Lake wells. At Pelican Lake, the Enhanced Oil Recovery waterflood test program was 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 87 new wells to be drilled as producers.

North America Horizon Oil Sands Project

Significant progress was achieved on the six billion barrel Horizon Oil Sands Project during the third quarter. The Design Basis Memorandum ("DBM") was completed and the EDS commenced, representing the detailed design of the project.

The 100% owned and operated Horizon Oil Sands Project is expected to be built in three phases and produce approximately 232,000 barrels per day of light, sweet synthetic crude oil. Management expects to have regulatory approval from provincial and federal authorities by late 2003 or early 2004. The third phase of engineering, EDS, will be complete in 2004. In addition, the financing plan will be optimized and finalized by the third quarter of 2004.

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. 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.

From a regulatory standpoint, the EUB and the federal responsible authority successfully concluded their Joint Panel hearing in Fort McMurray during September. With the hearing completed, Canadian Natural remains confident that key regulatory decisions for the Horizon Oil Sands Project will be provided by late 2003/early 2004.

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. If regulatory approval is received on a timely basis and Board of Directors approval is received based on acceptable certainty of forecasted capital costs, $50 million of pre-construction activities will be undertaken. Once the EDS is complete, a reasonable cost estimate is finalized, and Board of Director approval is obtained, up to an additional $400 million of construction activities could be undertaken in 2004.

The Company currently employs 110 full time employees and 345 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.

United Kingdom

Canadian Natural remains excited about continuing to create value from the crude oil fields at Ninian and Murchison. During the third quarter, the Company drilled two crude oil wells and one water injector well targeting unswept crude oil reserves within the Ninian and Murchison fields. Additionally, during the third quarter, the Company further consolidated ownership interests to 87.6% in the Banff Field located in the Central North Sea. The Company also assumed operatorship of the Banff Field and the adjoining Block 29/2a. Canadian Natural now operates 99% of its North Sea production and maintains an average ownership interest of about 80% in its properties. Finally, in late July 2003, Canadian Natural was the successful bidder on 6 new exploration licenses at the UK Government's 21st Seaward Licensing Round. These Blocks provide for additional exploration lands adjacent to the Ninian hub in the Northern North Sea.

During the third quarter, one unsuccessful exploration well was drilled into the French portion of the southwest approaches of the North Sea.

During the fourth quarter, Canadian Natural plans to drill a further 4 net crude oil and 3 net injector wells from the Ninian and Murchison platforms, including an exploratory drill into the Jude structure, a Ninian satellite.

In 2004, Canadian Natural anticipates drilling approximately 12 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. Average crude oil production is expected to increase by approximately 9%, however natural gas volumes will be lower as natural gas sales at Banff are diverted to reinjection. The 2004 capital budget for the North Sea is $340 million.

Offshore West Africa

During the third quarter Canadian Natural completed a fourth water injection well and an additional production well at the East Espoir Field located offshore Côte d'Ivoire. Production exited the quarter at approximately, 13,500 bbls/d, a level expected to be maintained during the fourth quarter, and 2004.

At the 57.61% owned and operated Baobab Field, also located offshore Côte d'Ivoire, field development of the estimated recoverable reserves of 200 million barrels of crude oil 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 bbls/d and subsequently peak at 60,000 bbls/d, will be sold directly from the FPSO, with the associated natural gas being transported to shore via the Espoir Field infrastructure. Development drilling will commence in early November.

In Offshore Angola, drilling of the Zenza project commenced on October 2nd. It is anticipated that results from this well will be available before year end. The Zenza prospect is located in 1,200 metres of water with a total drilling depth of 3,900 metres. Block 16, where the Company operates with a 50% working interest, represents a high risk/high impact exploration development for the Company in one of the most prolific crude oil regions of the world.

In 2004, the capital budget for Offshore West Africa is set at $350 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 and various exploration activities.

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 the first nine months of 2003, strong operational results and product pricing enabled the Company to repay approximately $726 million of long-term debt. The strength of the Canadian dollar during the half also reduced carrying values of US dollar based borrowings by an additional $419 million, resulting in a total decrease of long-term debt of $1,145 billion. Corporate debt to cash flow was reduced to 0.9 times versus 1.9 times at December 31, 2002, while debt to book capitalization improved to 33% from 46% at year-end 2002.

Continuing higher than budgeted prices received for the Company's products are expected to result in increased cash flow to the Company in 2003 over the capital budget established in late 2002. The Company has allocated 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 expenditures on conventional crude oil and natural gas opportunities. The largest portion of the additional capital expenditures will take place in the fourth quarter of 2003 and accordingly will not add materially to Canadian Natural's 2003 average production volumes. Should additional economic opportunities for share buy-backs or capital activities not materialize, such allocations of excess cash flow would revert to debt repayment. To date, 2.4 million common shares have been purchased for cancellation in 2003 under the Normal Course Issuer Bid.

Implementation of this allocation policy will result in additional capital expenditures of $125 million during the last quarter of 2003 and a final 2003 capital budget of $2,525 million.

In June 2003, the Company announced a small shareholders selling program, which allows registered and beneficial shareholders who own in aggregate 99 or fewer common shares to sell their shares without incurring any brokerage commission. This program was extended on September 2, 2003 and ends on November 28, 2003. Interest parties should contact Georgeson Shareholders Communications Canada, Inc. for further details at 1-866-869-7468.

CORPORATE REVIEW

Canadian Natural is pleased to announce that Mr. Allan Markin, Chairman of the Company, has returned to his day to day company activities following a short-term leave of absence.

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 nine months ended September 30, 2003 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2002.

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

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

		Three Months Ended			Nine Months Ended	
		Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Revenue		**$ 1,371**	$ 1,413	$ 1,173	**$ 4,412**	$ 2,753
Cash flow from operations attributable to common shareholders[1]		**$ 758**	$ 762	$ 643	**$ 2,426**	$ 1,477
Per common share	– basic	**$ 5.62**	$ 5.68	$ 4.83	**$ 18.06**	$ 11.73
	– diluted	**$ 5.56**	$ 5.57	$ 4.71	**$ 17.62**	$ 11.28
Net earnings attributable to common shareholders[2]		**$ 203**	$ 525	$ 117	**$ 1,156**	$ 361
Per common share	– basic	**$ 1.51**	$ 3.91	$ 0.88	**$ 8.61**	$ 2.87
	– diluted	**$ 1.49**	$ 3.78	$ 0.86	**$ 8.30**	$ 2.78
Business combination		**$ -**	$ -	$ 2,373	**$ -**	$ 2,373
Capital expenditures, net of dispositions		**$ 621**	$ 410	$ 620	**$ 1,844**	$ 1,384

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

	Three Months Ended			*Nine Months Ended*	
($ millions)	***Sep 30 2003***	*Jun 30 2003*	*Sep 30 2002*	***Sep 30 2003***	*Sep30 2002*
Net earnings attributable to common shareholders	***$ 203***	*$ 525*	*$ 117*	***$ 1,156***	*$ 361*
Non-cash items:					
Future tax on dividend on preferred securities	***(1)***	*(1)*	*(1)*	***(3)***	*(3)*
Revaluation of preferred securities (net of tax)	***-***	*(7)*	*6*	***(14)***	*-*
Stock-based compensation	***32***	*105*	*-*	***137***	*-*
Depletion, depreciation and amortization	***401***	*384*	*403*	***1,160***	*928*
Unrealized foreign exchange (gain) loss	***(11)***	*(109)*	*41*	***(239)***	*(35)*
Deferred petroleum revenue tax	***1***	*4*	*1*	***8***	*4*
Future income tax (recovery)	***133***	*(139)*	*76*	***221***	*222*
Cash flow from operations attributable to common shareholders	***$ 758***	*$ 762*	*$ 643*	***$ 2,426***	*$ 1,477*

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

Cash flow in the third quarter of 2003 reached record levels. Net earnings increased 74% to $203 million and increased 220% to $1,156 million for the three and nine months ended September 30, 2003 from the comparable periods in the prior year. Cash flow increased 18% to $758 million and 64% to $2,426 million for the three and nine months ended September 30, 2003 from the comparable periods in 2002. The increase in net earnings and cash flow for the nine months ended September 30, 2003 was a result of higher prices for crude oil, NGLs and natural gas and higher production volumes. The increase in production volumes was primarily associated with an active capital expenditure program, the consolidation of working interests in the North Sea, and the acquisition of Rio Alto Exploration Ltd. ("Rio Alto") on July 1, 2002. Net earnings and cash flow increased in the third quarter of 2003 from the prior year due to higher natural gas prices. Net earnings for the third quarter of 2003 decreased compared to the prior quarter due to the reduction in the Canadian federal and Alberta provincial corporate income tax rates and the larger foreign exchange gain on the Company's US dollar denominated debt in the second quarter of 2003. Cash flow in the third quarter of 2003 decreased from the prior quarter due to lower natural gas prices.

ANALYSIS OF QUARTERLY CHANGES IN REVENUE
($ millions)

	Crude oil and NGLs	Natural gas	Midstream	Total
September 30, 2002	$ 749	$ 411	$ 13	$ 1,173
Price variance	(57)	235	-	178
Volume variance	(5)	(18)	-	(23)
Other variance	-	-	2	2
December 31, 2002	687	628	15	1,330
Price variance	83	267	-	350
Volume variance	(15)	(40)	-	(55)
Other variance	-	-	3	3
March 31, 2003	755	855	18	1,628
Price variance	(110)	(136)	-	(246)
Volume variance	16	19	-	35
Other variance	-	-	(4)	(4)
June 30, 2003	661	738	14	1,413
Price variance	**15**	**(70)**	**-**	**(55)**
Volume variance	**30**	**(16)**	**-**	**14**
Other variance	**-**	**-**	**(1)**	**(1)**
September 30, 2003	$ **706**	$ **652**	$ **13**	$ **1,371**

OPERATING HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Crude oil and NGLs ($/bbl, except daily production)					
Daily production (bbls/d)	**247,016**	240,607	242,051	**241,762**	206,822
Sales price	**$ 30.97**	$ 30.27	$ 33.57	**$ 32.13**	$ 29.23
Royalties	**2.56**	2.78	3.56	**2.96**	3.01
Production expense	**10.14**	10.80	8.67	**10.57**	8.19
Netback	**$ 18.27**	$ 16.69	$ 21.34	**$ 18.60**	$ 18.03
Natural gas ($/mcf, except daily production)					
Daily production (mmcf/d)	**1,289**	1,325	1,427	**1,308**	1,188
Sales price	**$ 5.50**	$ 6.12	$ 3.13	**$ 6.29**	$ 3.28
Royalties	**1.11**	1.35	0.67	**1.41**	0.67
Production expense	**0.63**	0.59	0.55	**0.60**	0.57
Netback	**$ 3.76**	$ 4.18	$ 1.91	**$ 4.28**	$ 2.04
Barrels of oil equivalent ($/boe, except daily production)					
Daily production (boe/d)	**461,882**	461,455	479,949	**459,785**	404,745
Sales price	**$ 31.94**	$ 33.32	$ 26.26	**$ 34.79**	$ 24.57
Royalties	**4.46**	5.32	3.80	**5.57**	3.49
Production expense	**7.17**	7.34	6.01	**7.26**	5.85
Netback	**$ 20.31**	$ 20.66	$ 16.45	**$ 21.96**	$ 15.23

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
WTI benchmark price (US $/bbl)	**$ 30.20**	$ 28.90	$ 28.25	**$ 30.96**	$ 25.42
Differential to LLB blend (US $/bbl)	**$ 8.72**	$ 7.18	$ 5.97	**$ 7.93**	$ 5.91
Condensate benchmark price (US $/bbl)	**$ 29.97**	$ 29.88	$ 28.14	**$ 31.37**	$ 25.14
NYMEX benchmark price (US $/mmbtu)	**$ 5.10**	$ 5.48	$ 3.26	**$ 5.74**	$ 3.01
AECO benchmark price (Cdn $/mmbtu)	**$ 6.28**	$ 6.99	$ 3.25	**$ 7.07**	$ 3.68
US/Canadian dollar exchange rate (US $)	**$ 0.72**	$ 0.72	$ 0.64	**$ 0.70**	$ 0.64

World crude oil prices have remained strong throughout 2003 due to concerns over supply relating to the war in Iraq, the strike in Venezuela and the unrest in Nigeria. West Texas Intermediate ("WTI") averaged US $30.20 per bbl in the third quarter of 2003, up 5% compared to US $28.90 per bbl in the prior quarter, and up 7% from US $28.25 per bbl compared to the third quarter of 2002. WTI prices averaged US $30.96 per bbl for the nine months ended September 30, 2003, up 22% compared to the prior year.

Natural gas prices fell in the third quarter of 2003 to their lowest levels of the year but continue to remain higher than the prior year. NYMEX natural gas spot price averaged US $5.10 per mmbtu in the third quarter of 2003, down 7% compared to US $5.48 per mmbtu in the prior quarter, but up 56% compared to the third quarter of 2002. AECO natural gas price averaged $6.28 per mmbtu in the third quarter of 2003, down 10% compared to $6.99 per mmbtu in the prior quarter, but up 93% compared to the third quarter of 2002. The decrease in natural gas prices in the third quarter of 2003 was due to reduced industrial demand and the increase in natural gas storage levels.

PRODUCT PRICES

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Crude oil and NGLs ($/bbl)					
North America	**$ 27.48**	$ 27.64	$ 31.07	**$ 28.42**	$ 26.85
North Sea	**$ 39.84**	$ 37.83	$ 41.68	**$ 42.59**	$ 38.77
Offshore West Africa	**$ 37.37**	$ 34.34	$ 42.78	**$ 36.50**	$ 38.95
Company average	**$ 30.97**	$ 30.27	$ 33.57	**$ 32.13**	$ 29.23
Natural gas ($/mcf)					
North America	**$ 5.62**	$ 6.25	$ 3.15	**$ 6.41**	$ 3.29
North Sea	**$ 2.57**	$ 2.21	$ 1.98	**$ 2.91**	$ 2.56
Offshore West Africa	**$ 4.59**	$ 5.09	$ 4.97	**$ 4.60**	$ 4.97
Company average	**$ 5.50**	$ 6.12	$ 3.13	**$ 6.29**	$ 3.28
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**52.0%**	47.3%	64.6%	**48.6%**	60.9%
Natural gas	**48.0%**	52.7%	35.4%	**51.4%**	39.1%

Realized crude oil prices decreased for the three months ended September 30, 2003 from the comparable period in 2002 for all segments. Realized crude oil prices increased for the nine months ended September 30, 2003 from the comparable period in 2002 due to the higher world crude oil price resulting from concerns surrounding supply. North America realized crude oil prices decreased in the third quarter of 2003 from the prior quarter as a result of the higher heavy oil differential and the stronger Canadian dollar. Heavy oil differentials averaged US $8.72 per bbl in the third quarter of 2003, up 46% from US $5.97 per bbl in the third quarter of 2002 and up 21% from US $7.18 per bbl in the second quarter of 2003. The Offshore West Africa realized crude oil price decreased due to the timing of and prices received on specific product lifting dates. The North Sea and Offshore West Africa realized crude oil prices increased in the third quarter compared to the prior quarter due to the narrowing of the Brent differential. As a result of the use of derivative financial instruments, the realized price from the sale of crude oil was reduced by $0.48 per bbl in the quarter ended September 30, 2003 ($0.39 per bbl and $1.62 per bbl reduction, respectively, in the quarters ended June 30, 2003 and September 30, 2002).

The Company's average natural gas price increased 76% to $5.50 per mcf for the three months ended September 30, 2003 and increased 92% to $6.29 per mcf for the nine months ended September 30, 2003 from the comparable periods in 2002 due to supply and demand concerns in North America. The Company's average natural gas price decreased 10% in the third quarter from the prior quarter due to the decrease in demand and the easing of concerns surrounding storage levels heading into the winter heating season. Derivative financial instruments entered into by the Company on its natural gas portfolio affects realized prices. The price realized from the sale of its natural gas was decreased by $0.07 per mcf in the third quarter of 2003 ($0.13 per mcf reduction and $0.05 per mcf increase, respectively, in the quarters ended June 30, 2003 and September 30, 2002).

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

	Q3 2003	Q2 2003	Q3 2002
Canadian Natural's Wellhead Price[1]			
Light crude oil and NGLs (Cdn $/bbl)	**$ 34.37**	$ 35.54	$ 34.36
Pelican Lake crude oil (Cdn $/bbl)	**$ 27.20**	$ 25.66	$ 30.58
Primary heavy crude oil (Cdn $/bbl)	**$ 24.93**	$ 24.76	$ 30.11
Thermal heavy crude oil (Cdn $/bbl)	**$ 23.58**	$ 24.22	$ 29.23
Natural gas (Cdn $/mcf)	**$ 5.62**	$ 6.25	$ 3.15

(1) *Including financial instruments.*

DAILY PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Crude oil and NGLs (bbls/d)					
North America	**174,838**	175,232	185,990	**174,378**	165,608
North Sea	**60,193**	55,781	47,114	**57,658**	34,629
Offshore West Africa	**11,985**	9,594	8,947	**9,726**	6,585
Total	**247,016**	240,607	242,051	**241,762**	206,822
Natural gas (mmcf/d)					
North America	**1,229**	1,278	1,395	**1,258**	1,162
North Sea	**49**	40	29	**43**	25
Offshore West Africa	**11**	7	3	**7**	1
Total	**1,289**	1,325	1,427	**1,308**	1,188
Product mix					
Light crude oil and NGLs	**25.7%**	24.3%	21.4%	**24.9%**	20.2%
Pelican Lake crude oil	**5.1%**	5.6%	6.7%	**5.4%**	7.4%
Primary heavy crude oil	**14.8%**	13.8%	13.9%	**14.0%**	13.7%
Thermal heavy crude oil	**7.9%**	8.4%	8.4%	**8.3%**	9.8%
Natural gas	**46.5%**	47.9%	49.6%	**47.4%**	48.9%

Crude oil and NGLs production for the three and nine months ended September 30, 2003 increased 2% or 4,965 bbls/d and 17% or 34,940 bbls/d respectively from the comparable periods in 2002. Crude oil and NGLs production for the third quarter of 2003 was in line with the Company's guidance previously provided.

Crude oil and NGLs production in North America for the three months ended September 30, 2003 decreased 6% or 11,152 bbls/d from the comparable period in 2002 but remained relatively consistent with the prior quarter. The decrease in North American crude oil production was due to reduced crude oil drilling activity in the fourth quarter of 2002 and the first quarter of 2003, reflecting the increased focus on natural gas drilling. Crude oil and NGLs production in North America for the nine months ended September 30, 2003 increased 5% or 8,770 bbls/d from the comparable period in 2002 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 production from the North Sea for the three and nine months ended September 30, 2003 increased 28% or 13,079 bbls/d and 67% or 23,029 bbls/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 third quarter increased 8% or 4,412 bbls/d from the previous quarter due to the completion of an extensive turnaround on the Ninian South Platform in the second quarter. Production also increased as a result of in-fill drilling in the Ninian, Murchison and Columba Fields; the re-entry into a number of producing wells to access behind pipe reserves; and the continued consolidation of the Company's working interests in the North Sea.

Offshore West Africa crude oil production for the three and nine months ended September 30, 2003 increased 34% or 3,038 bbls/d and 48% or 3,141 bbls/d from the comparable periods in 2002. In addition, crude oil production in the third quarter increased 25% or 2,391 bbls/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 third quarter of 2003 was in line with the Company's guidance previously provided. Natural gas production in the third quarter continued to represent the Company's largest product offering but decreased 10% or 138 mmcf/d from the comparable period in 2002. The decrease was due to third quarter drilling activity, 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 for the nine months ended September 30, 2003 increased 10% or 120 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 decreased 3% or 36 mmcf/d from the prior quarter due to normal production declines. Production from the Ladyfern field in Northeast British Columbia declined 15 mmcf/d to average 47 mmcf/d during the third quarter of 2003, down from 62 mmcf/d in the second quarter of 2003 and 178 mmcf/d in the third quarter of 2002 as well pressures continue to decline. In addition, on September 1, 2003 approximately 11 mmcf/d of the Company's natural gas production in the Athabasca Wabiskaw-McMurray oilsands area was shut in pursuant to the decision of the Alberta Energy and Utilities Board.

Natural gas production in the North Sea increased from the comparable periods in the prior year and the prior quarter due to the increased working interests acquired in the Banff Field as a result of the Company's consolidation of its working interest in the North Sea.

Natural gas production in Offshore West Africa increased over the comparable period in the prior year due to the natural gas pipeline commencing operation in the third quarter of 2002. Natural gas production increased in the third quarter of 2003 due to the perforation of the upper zone of the East Espoir structure in the second quarter of 2003. In addition, production increased as a result of the drilling of an additional producing well in the third quarter of 2003.

The Company expects fourth quarter production levels to average 1,255 to 1,280 mmcf/d of natural gas and 240,000 to 250,000 bbls/d of crude oil and NGLs. This results in expected annual production levels of approximately 1,295 to 1,300 mmcf/d of natural gas and 241,000 to 245,000 bbls/d of crude oil and NGLs in 2003.

ROYALTIES

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Crude oil and NGLs ($/bbl)					
North America	**$ 3.52**	$ 3.83	$ 3.92	**$ 4.04**	$ 3.28
North Sea	**$ 0.09**	$ (0.19)	$ 2.56	**$ -**	$ 2.06
Offshore West Africa	**$ 1.13**	$ 0.99	$ 1.34	**$ 1.10**	$ 1.36
Company average	**$ 2.56**	$ 2.78	$ 3.56	**$ 2.96**	$ 3.01
Natural gas ($/mcf)					
North America	**$ 1.16**	$ 1.40	$ 0.69	**$ 1.46**	$ 0.68
Offshore West Africa	**$ 0.14**	$ 0.15	$ 0.15	**$ 0.14**	$ 0.15
Company average	**$ 1.11**	$ 1.35	$ 0.67	**$ 1.41**	$ 0.67
Company average ($/boe)	**$ 4.46**	$ 5.32	$ 3.80	**$ 5.57**	$ 3.49
Percentage of revenue (excluding financial instruments)					
Crude oil and NGLs	**8.2%**	9.1%	10.1%	**8.8%**	9.8%
Natural gas	**19.8%**	21.6%	21.8%	**21.6%**	20.4%

North America crude oil and NGLs royalties for the three months ended September 30, 2003 decreased on a per barrel basis from the comparable period in 2002 and the prior quarter due to lower crude oil prices as a result of the higher heavy oil differential. North America crude oil and NGLs royalties for the nine months ended September 30, 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 royalties.

North Sea crude oil royalties decreased from the comparable periods in the prior year as a result of the elimination of government royalties in the North Sea effective January 1, 2003. In the second quarter of 2003, the Company received a refund of royalties previously provided for related to the Ninian Field.

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

PRODUCTION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Crude oil and NGLs ($/bbl)					
North America	**$ 9.27**	$ 9.80	$ 6.10	**$ 9.39**	$ 6.50
North Sea	**$ 13.25**	$ 14.17	$ 18.30	**$ 14.29**	$ 15.25
Offshore West Africa	**$ 7.11**	$ 9.32	$ 11.23	**$ 9.61**	$ 13.60
Company average	**$ 10.14**	$ 10.80	$ 8.67	**$ 10.57**	$ 8.19
Natural gas ($/mcf)					
North America	**$ 0.58**	$ 0.56	$ 0.52	**$ 0.57**	$ 0.54
North Sea	**$ 1.60**	$ 1.45	$ 1.78	**$ 1.39**	$ 1.65
Offshore West Africa	**$ 1.24**	$ 1.45	$ 1.77	**$ 1.51**	$ 1.77
Company average	**$ 0.63**	$ 0.59	$ 0.55	**$ 0.60**	$ 0.57
Company average ($/boe)	**$ 7.17**	$ 7.34	$ 6.01	**$ 7.26**	$ 5.85

The cost of natural gas used to generate steam to heat the Company's thermal crude oil formations in the Primrose area of Alberta decreased, while the steam/crude oil ratios remained relatively constant, resulting in a decrease in the North America crude oil and NGLs production expense compared to the previous quarter. Third quarter 2003 production expense decreased from the prior quarter as a result of increased production volumes coming on stream as a result of the work associated with the heavy crude oil drilling and recompletion programs. The decrease in North America crude oil and NGLs production expense 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 while implementing the waterflood pilots.

North Sea crude oil production expense for the three months ended September 30, 2003 decreased on a per barrel basis from both the prior quarter and the comparable period in 2002 due to increased volumes on a relatively fixed cost lease and the timing of maintenance work. North Sea crude oil production expense for the nine months ended September 30, 2003 decreased from the prior year due to the overall impact of increased volumes on relatively fixed costs.

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 in the third quarter of 2003 increased marginally from both the prior quarter and the comparable period 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 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 for the three and nine months ended September 30, 2003 as production volumes increased while costs remained relatively fixed.

MIDSTREAM ($ millions)

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Revenue	**$ 13**	$ 14	$ 13	**$ 45**	$ 37
Operating costs	**3**	3	3	**11**	10
Operating cash flow	**10**	11	10	**34**	27
Depreciation	**2**	2	2	**6**	6
Segment earnings before taxes	**$ 8**	$ 9	$ 8	**$ 28**	$ 21

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 nine months ended September 30, 2003 from the comparable period in 2002 due to higher electricity prices received in the first quarter of 2003 and increased revenue generated by the ECHO pipeline. Revenue from the Company's midstream assets is expected to increase with the completion of the expansion of the ECHO pipeline capacity to 72 mbbls/d from 58 mbbls/d in October 2003.

DEPLETION, DEPRECIATION AND AMORTIZATION

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Expense ($ millions)	**$ 399**	$ 382	$ 401	**$ 1,154**	$ 922
$/boe	**$ 9.41**	$ 9.09	$ 9.08	**$ 9.20**	$ 8.35

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

DD&A for the nine months ended September 30, 2003 increased in total and per boe from the comparable period 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. DD&A increased from the prior quarter in total and per boe due to higher finding and development costs, including higher future costs to develop, and the write-off of costs associated with the unsuccessful well in offshore France.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Net expense *($ millions)*	**$ 22**	$ 23	$ 18	**$ 63**	$ 44
$/boe	**$ 0.51**	$ 0.56	$ 0.40	**$ 0.50**	$ 0.39

Administration expense for the three and nine months ended September 30, 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 production and the expanding asset base.

STOCK-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Expense ($ millions)	**$ 32**	$ 105	$ -	**$ 137**	$ -
$/boe	**$ 0.77**	$ 2.49	$ -	**$ 1.10**	$ -

In June 2003, the Board of Directors approved an amendment to the Company's Stock Option Plan (the "Option Plan") that provides current employees, officers and directors (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options exercised. The amendment to the Option Plan balances the need for a long-term compensation program to retain employees and the concerns of shareholders regarding the dilution caused by stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are expensed. The 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 $124 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 $137 million ($93 million after tax). The liability will be revalued quarterly to reflect changes in the market price of the Company's common shares and the net change will be recognized in net earnings for the quarter. For the period ended September 30, 2003, the Company has paid $10 million for stock options surrendered for cash settlement.

INTEREST EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Interest expense *($ millions)*	**$ 35**	$ 41	$ 49	**$ 124**	$ 106
$/boe	**$ 0.83**	$ 0.98	$ 1.11	**$ 0.99**	$ 0.96
Average effective interest rate	**4.5%**	4.9%	4.5%	**4.8%**	4.3%

Interest expense for the three months ended September 30, 2003 decreased from both the comparable period in the prior year and the previous quarter due to lower debt levels as the Company used excess cash flow generated to repay $726 million of long-term debt in 2003. Interest expense for the nine months ended September 30, 2003 increased from the comparable period in 2002 due to higher debt levels associated with the acquisition of Rio Alto on July 1, 2002. The interest expense was also affected by the increase in the Company's effective interest rate resulting from increases in the Canadian prime lending rate and a greater proportion of higher fixed rate debt. This was partially offset as the strengthening Canadian dollar reduced the Canadian equivalent interest expense on the Company's US dollar denominated debt.

FOREIGN EXCHANGE ($ millions)

	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Realized foreign exchange loss (gain)	**$ 3**	$ 10	$ (1)	**$ 14**	$ 2
Unrealized foreign exchange (gain) loss	**(11)**	(109)	41	**(239)**	(35)
Total	**$ (8)**	$ (99)	$ 40	**$ (225)**	$ (33)

The Canadian dollar continues to strengthen against the US dollar in 2003. The Canadian dollar increased to US $0.74 at the end of the third quarter compared to US $0.63 at January 1, 2003 and at September 30, 2002, resulting in an unrealized foreign exchange gain on the Company's US dollar denominated debt.

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

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets. For the three and nine months ended September 30, 2003, foreign exchange gains of $3 million and $136 million respectively (September 30, 2002 – $42 million for the three and nine months ended) were included in the foreign currency translation adjustment.

TAXES ($ millions, except income tax rates)

Taxes other than income tax	Three Months Ended **Sep 30 2003**	Jun 30 2003	Sep 30 2002	Nine Months Ended **Sep 30 2003**	Sep 30 2002
Current	**$ 28**	$ 20	$ 13	**$ 73**	$ 38
Deferred	**1**	4	1	**8**	4
Total	**$ 29**	$ 24	$ 14	**$ 81**	$ 42
Current income tax					
North Sea	**$ 5**	$ 1	$ 3	**$ 21**	$ 16
Offshore West Africa	**3**	2	3	**7**	5
North America – Current income tax	**12**	12	-	**40**	-
North America – Large corporations tax	**5**	4	6	**15**	15
Total	**$ 25**	$ 19	$ 12	**$ 83**	$ 36
Future income tax	**$ 133**	$ (139)	$ 76	**$ 221**	$ 222
Effective income tax rate	**43.6%**	(30.0%)	41.7%	**21.0%**	41.5%

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. Third quarter taxes other than income taxes increased from the previous quarter due to higher realized crude oil prices and the increased production.

North Sea current income tax in the first nine months of 2003 increased from the previous year due to the introduction of the supplementary charge of 10% on profits from UK North Sea crude oil and natural gas production. The North Sea supplementary charge, which took effect April 17, 2002, is in addition to the corporate tax rate of 30% and excludes any deduction for financing costs. Current income tax in the third quarter 2003 increased from the second quarter due to higher operating income as a result of higher prices and increased production.

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

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

Future income tax expense for the three months ended September 30, 2003 increased over the comparable three-month periods due to higher taxable income generated by high product prices.

CAPITAL EXPENDITURES ($ millions)	Three Months Ended			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Business combinations	**$ -**	$ -	$ 2,373	**$ -**	$ 2,373
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 106**	$ 23	$ 333	**$ 307**	$ 401
Land acquisition and retention	**53**	36	48	**110**	95
Seismic evaluations	**12**	21	5	**52**	44
Well drilling, completion and equipping	**256**	190	144	**842**	487
Pipeline and production facilities	**133**	107	56	**389**	247
Total net reserve replacement expenditures	**560**	377	586	**1,700**	1,274
Horizon Oil Sands Project	**32**	27	10	**100**	49
Midstream	**5**	1	-	**9**	15
Abandonments	**14**	3	20	**20**	39
Head office	**10**	2	4	**15**	7
Total net capital expenditures	**$ 621**	$ 410	$ 620	**$ 1,844**	$ 1,384
North America	**$ 407**	$ 288	$ 307	**$ 1,338**	$ 902
North Sea	**99**	43	222	**232**	203
Offshore West Africa	**54**	46	57	**130**	169
Horizon Oil Sands Project	**32**	27	10	**100**	49
Midstream	**5**	1	-	**9**	15
Abandonments	**14**	3	20	**20**	39
Head office	**10**	2	4	**15**	7
Total	**$ 621**	$ 410	$ 620	**$ 1,844**	$ 1,384

During the third quarter of 2003, the Company drilled 374 successful net wells, comprised of 278 net natural gas wells, 93 net crude oil wells and three stratigraphic/service test wells. During the first nine months of the year, the Company has drilled a total of 577 net natural gas wells and 366 net crude oil wells, a 285% and a 45% increase respectively over the comparable period in 2002. North America third quarter drilling was concentrated in the Company's heavy crude oil area of North Alberta/West Saskatchewan and on the summer shallow natural gas program where 196 net wells were drilled in South Alberta. North America capital expenditures also include the expansion of the Company's Primrose properties and the acquisition of the West Stoddart natural gas plant. The West Stoddart natural gas plant is located 50 kilometres northwest of Fort St. John, British Columbia and has a processing capacity of 120 mmcf/d.

Capital expenditures also included work on the Horizon Oil Sands Project ("Horizon Project") where the Design Basis Memorandum was completed. Work on the Engineering Design Study ("EDS"), the third and final stage of engineering work, has commenced and is expected to be completed by mid-2004. Work also continued on the access road, including the construction of three bridges. The Alberta Energy and Utilities Board ("EUB") and Alberta Environment, in co-operation with other Provincial and Federal regulatory agencies, have deemed the application for the Horizon Project as being complete. Regulatory review for the environmental assessment of the Horizon Project was conducted in September 2003 and the Company expects to receive project approval in late 2003 or early 2004.

During the third quarter, the Company drilled two crude oil wells and one water injector well targeting unswept crude oil reserves within the Ninian and Murchison fields. Additionally, during the third quarter the Company further consolidated ownership interests to 87.6% in the Banff Field located in the Central North Sea. The Company acquired an additional 31.7% working interest and assumed operatorship of the Banff Field and Block 29/2a. In addition, the Company was the successful bidder on six new exploration licenses at the UK Governments' 21st Seaward Licensing Round. These Blocks provide for additional exploration lands adjacent to the Ninian hub in the Northern North Sea. The third quarter also saw the drilling of one unsuccessful exploration well in the French portion of the southwest approaches of the North Sea.

During the third quarter, Canadian Natural completed a fourth water injection well and an additional production well at the Espoir Field located offshore Côte d'Ivoire. Development of the Baobab Field continues with four major contracts being awarded in the third quarter of 2003 for the drilling; supply of subsea Xmas trees, manifolds, flowlines, controls and associated equipment; the supply and operation of a Floating Production, Storage and Offtake vessel; and the supply of pipelines, risers and installation of all of the subsea equipment. The drilling of the wells will commence in the fourth quarter of 2003 with crude oil production commencing in the first half of 2005.

LIQUIDITY AND CAPITAL RESOURCES
($ millions, except ratios)

	Sep 30 2003	Jun 30 2003	Dec 31 2002	Sep 30 2002
Working capital deficit (1)	$ 528	$ 459	$ 14	$ 364
Long-term debt	2,766	2,904	4,074	4,170
Total	$ 3,294	$ 3,363	$ 4,088	$ 4,534
Shareholders' equity				
Preferred securities	$ 108	$ 108	$ 126	$ 127
Share capital	2,348	2,360	2,304	2,289
Retained earnings	3,428	3,285	2,414	2,222
Foreign currency translation adjustment	9	10	24	23
Total	$ 5,893	5,763	4,868	4,661
Debt to cash flow(1) (2)	0.9x	1.0x	1.9x	2.4x
Debt to book capitalization(1)	33.4%	35.0%	45.7%	47.4%
Debt to market capitalization(1)	28.1%	29.7%	39.1%	38.0%
After tax return on average common shareholders' equity(2)	26.4%	26.7%	13.8%	10.6%
After tax return on average capital employed(2)	16.4%	16.5%	8.9%	7.2%

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

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. During the third quarter, long-term debt was reduced by $148 million through debt repayments and $5 million as a result of foreign exchange gains on the Company's US dollar denominated debt. In the first nine months of 2003, $726 million of long-term debt was repaid. Long-term debt was also reduced by an additional $419 million as a result of foreign exchange gains. Higher than budgeted prices received for the Company's products during the first half of 2003 have resulted in increased cash flow to the Company in 2003 over the budget established in late 2002. The Company has allocated 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 will take place in the fourth quarter of 2003 and accordingly will not add materially to Canadian Natural's 2003 average production volumes. Should additional economic opportunities for share buy-backs or capital activities not materialize, such allocations of excess cash flow would revert to debt repayment.

On January 22, 2003, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,692,799 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As of November 4, 2003, the Company had purchased 2,434,800 common shares for a total cost of $125 million (September 30, 2003 – 2,404,800 common shares for a total cost of $123 million).

On September 2, 2003, the Company announced the extension of its small shareholder selling program ("the program"), which enables registered and beneficial shareholders who own in aggregate 99 or fewer common shares of the Company as of June 13, 2003 ("Eligible Shareholders") to sell their shares without incurring any brokerage commission. The sale of shares will be executed through the facilities of the Toronto Stock Exchange. The voluntary program ends on November 28, 2003 and is designed to assist Eligible Shareholders in selling their shares in a convenient and inexpensive manner.

COMMITMENTS

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

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	$92	$0.69	$65	$0.49
Including financial derivatives	$63	$0.47	$45	$0.34
Natural gas – AECO Cdn $0.10/mcf[3]				
Excluding financial derivatives	$33	$0.25	$21	$0.15
Including financial derivatives	$33	$0.25	$21	$0.15
Volume changes				
Crude oil – 10,000 bbls/d	$53	$0.40	$19	$0.14
Natural gas – 10 mmcf/d	$14	$0.11	$6	$0.04
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $[3]				
Excluding financial derivatives	$53	$0.39	$19	$0.14
Including financial derivatives	$45	$0.33	$13	$0.10
Interest rate change - 1%	$11	$0.08	$11	$0.08

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in 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			Nine Months Ended	
	Sep 30 2003	Jun 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Daily production (boe/d)	**461,882**	461,455	479,949	**459,785**	404,745
Sales price	**$ 31.94**	$ 33.32	$ 26.26	**$ 34.79**	$ 24.57
Royalties	**4.46**	5.32	3.80	**5.57**	3.49
Production expense	**7.17**	7.34	6.01	**7.26**	5.85
Netback	**20.31**	20.66	16.45	**21.96**	15.23
Midstream contribution	**(0.24)**	(0.25)	(0.23)	**(0.27)**	(0.25)
Administration	**0.51**	0.56	0.40	**0.50**	0.39
Interest	**0.83**	0.98	1.11	**0.99**	0.96
Foreign exchange loss (gain)	**0.11**	0.23	(0.04)	**0.12**	0.01
Taxes other than income tax (current)	**0.64**	0.48	0.29	**0.58**	0.35
Current income tax (North Sea)	**0.10**	0.02	0.07	**0.17**	0.15
Current income tax (Offshore West Africa)	**0.07**	0.04	0.08	**0.05**	0.05
Current income tax (North America)	**0.28**	0.28	-	**0.32**	-
Current income tax (Large corporations tax)	**0.12**	0.12	0.13	**0.12**	0.13
Cash flow	**$ 17.89**	$ 18.20	$ 14.6	**$ 19.38**	$ 13.44

SEGMENTED NETBACK	Nine Months Ended September 30, 2003			
	North America	North Sea	Offshore West Africa	Total
Crude oil and NGLs ($/bbl, except daily production)				
Daily production (bbls/d)	174,378	57,658	9,726	241,762
Sales price	$ 28.42	$ 42.59	$ 36.50	$ 32.13
Royalties	4.04	-	1.10	2.96
Production expense	9.39	14.29	9.61	10.57
Netback	$ 14.99	$ 28.30	$ 25.79	$ 18.60
Natural gas ($/mcf, except daily production)				
Daily production (mmcf/d)	1,258	43	7	1,308
Sales price	$ 6.41	$ 2.91	$ 4.60	$ 6.29
Royalties	1.46	-	0.14	1.41
Production expense	0.57	1.39	1.51	0.60
Netback	$ 4.38	$ 1.52	$ 2.95	$ 4.28
Barrels of oil equivalent ($/boe, except daily production)				
Daily production (boe/d)	383,955	64,882	10,948	459,785
Sales price	$ 33.92	$ 39.79	$ 35.50	$ 34.79
Royalties	6.63	-	1.07	5.57
Production expense	6.12	13.62	9.55	7.26
Netback	$ 21.17	$ 26.17	$ 24.88	$ 21.96

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)		September 30 2003		December 31 2002
ASSETS				
Current assets				
Cash	**$**	**30**	$	30
Accounts receivable and other		**763**		745
		793		775
Property, plant and equipment (net)		**13,007**		12,500
Deferred charges		**79**		84
	$	**13,879**	$	13,359
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**486**	$	337
Accrued liabilities		**648**		428
Current portion of long-term debt (note 3)		**187**		24
		1,321		789
Long-term debt (note 3)		**2,766**		4,074
Deferred credits (note 4)		**459**		440
Future income tax (note 5)		**3,440**		3,188
		7,986		8,491
SHAREHOLDERS' EQUITY				
Preferred securities		**108**		126
Share capital (note 6)		**2,348**		2,304
Retained earnings		**3,428**		2,414
Foreign currency translation adjustment (note 7)		**9**		24
		5,893		4,868
	$	**13,879**	$	13,359

Commitments (note 11)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Sep 30 2003**	Three Months Ended Sep 30 2002	Nine Months Ended **Sep 30 2003**	Nine Months Ended Sep 30 2002
Revenue	**$ 1,371**	$ 1,173	**$ 4,412**	$ 2,753
Less: royalties	**(190)**	(168)	**(699)**	(386)
	1,181	1,005	**3,713**	2,367
Expenses				
Production	**308**	268	**923**	656
Depletion, depreciation and amortization	**401**	403	**1,160**	928
Administration	**22**	18	**63**	44
Stock-based compensation (note 6)	**32**	-	**137**	-
Interest	**35**	49	**124**	106
Foreign exchange (gain) loss	**(8)**	40	**(225)**	(33)
	790	778	**2,182**	1,701
Earnings before taxes	**391**	227	**1,531**	666
Taxes other than income tax	**29**	14	**81**	42
Current income tax (note 5)	**25**	12	**83**	36
Future income tax (note 5)	**133**	76	**221**	222
Net earnings	**204**	125	**1,146**	366
Dividend on preferred securities (net of tax)	**(1)**	(2)	**(4)**	(5)
Revaluation of preferred securities (net of tax)	**-**	(6)	**14**	-
Net earnings attributable to common shareholders	**$ 203**	$ 117	**$ 1,156**	$ 361
Net earnings attributable to common shareholders per common share (note 8)				
Basic	**$ 1.51**	$ 0.88	**$ 8.61**	$ 2.87
Diluted	**$ 1.49**	$ 0.86	**$ 8.30**	$ 2.78

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Nine Months Ended September 30 **2003**	Nine Months Ended September 30 2002
Balance – beginning of period	**$ 2,414**	$ 1,908
Net earnings	**1,146**	366
Dividend on common shares (note 6)	**(61)**	(47)
Purchase of common shares (note 6)	**(81)**	-
Dividend on preferred securities (net of tax)	**(4)**	(5)
Revaluation of preferred securities (net of tax)	**14**	-
Balance – end of period	**$ 3,428**	$ 2,222

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2003	Three Months Ended Sep 30 2002	Nine Months Ended Sep 30 2003	Nine Months Ended Sep 30 2002
Operating activities				
Net earnings	**$ 204**	$ 125	**$ 1,146**	$ 366
Non-cash items				
Depletion, depreciation and amortization	**401**	403	**1,160**	928
Deferred petroleum revenue tax	**1**	1	**8**	4
Stock-based compensation	**32**	-	**137**	-
Future income tax	**133**	76	**221**	222
Unrealized foreign exchange (gain) loss	**(11)**	41	**(239)**	(35)
Cash flow provided from operations	**760**	646	**2,433**	1,485
Deferred charges	**3**	(58)	**5**	(58)
Net change in non-cash working capital	**91**	(44)	**(89)**	(57)
	854	544	**2,349**	1,370
Financing activities				
Repayment of bank credit facilities	**(133)**	(326)	**(634)**	(1,149)
Repayment of senior unsecured notes	**(14)**	(16)	**(85)**	(16)
Issue of US debt securities	**-**	1,107	**-**	1,749
Repayment of lease obligations	**(1)**	(2)	**(7)**	(2)
Issue of capital stock	**4**	10	**83**	69
Purchase of common shares	**(58)**	-	**(123)**	-
Dividend on common shares	**(20)**	(16)	**(57)**	(43)
Dividend on preferred securities	**(2)**	(3)	**(7)**	(8)
Net change in non-cash working capital	**6**	(17)	**(2)**	(17)
	(218)	737	**(832)**	583
Investing activities				
Business combination, net of cash acquired	**-**	(843)	**-**	(843)
Expenditures on property, plant and equipment	**(622)**	(635)	**(1,863)**	(1,457)
Net proceeds on sale of property, plant and equipment	**1**	15	**19**	73
Net expenditures on property, plant and equipment	**(621)**	(1,463)	**(1,844)**	(2,227)
Net change in non-cash working capital	**(3)**	196	**327**	274
	(624)	(1,267)	**(1,517)**	(1,953)
Increase in cash	**12**	14	**-**	-
Cash – beginning of period	**18**	1	**30**	15
Cash – end of period	**$ 30**	$ 15	**$ 30**	$ 15

Supplemental disclosure of cash flow information (note 9)

Notes to the consolidated financial statements (tabular amounts in millions of Canadian dollars, unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2002, except as described in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2002.

2. ACCOUNTING POLICY

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

Stock-based compensation

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

3. LONG-TERM DEBT

	Sep 30 2003	Dec 31 2002
Bank credit facilities		
Canadian dollar debt	**$ 12**	$ 728
US dollar debt (2003 – US $210 million, 2002 – US $150 million)	**284**	237
Medium-term notes	**250**	250
Senior unsecured notes (2003 – US $258 million, 2002 – US $318 million)	**373**	499
US dollar debt securities (2003 – US $1,500 million, 2002 – US $1,500 million)	**2,026**	2,369
Obligations under capital leases	**8**	15
	2,953	4,098
Less: current portion of long-term debt	**187**	24
	$ 2,766	$ 4,074

Bank credit facilities

At September 30, 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 reducing 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. During the first quarter of 2003, the Company repaid and cancelled a $500 million acquisition term credit facility.

In addition to the outstanding debt, letters of credit aggregating $13 million have been issued.

Medium-term notes

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

Senior unsecured notes

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

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

	Sep 30 2003	Dec 31 2002
Provision for future site restoration	**$ 439**	$ 440
Stock-based compensation	**20**	-
	$ 459	$ 440

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Current income tax expense				
Current income tax – North America	**$ 12**	$ -	**$ 40**	$ -
Large corporations tax – North America	**5**	6	**15**	15
Current income tax – North Sea	**5**	3	**21**	16
Current income tax – Offshore West Africa	**3**	3	**7**	5
	25	12	**83**	36
Future income tax	**133**	76	**221**	222
Income taxes	**$ 158**	$ 88	**$ 304**	$ 258

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

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

6. SHARE CAPITAL

Issued

	Nine months ended September 30, 2003	
Common shares	**Number of shares (thousands)**	**Amount**
Balance – beginning of period	**133,776**	**$ 2,304**
Issued upon exercise of stock options	**2,503**	**83**
Previously recognized liability on stock options surrendered for common shares	**-**	**3**
Purchase of shares under Normal Course Issuer Bid	**(2,405)**	**(42)**
Balance – end of period	**133,874**	**$ 2,348**

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 September 30, 2003, the Company had purchased 2,404,800 common shares for a total cost of $123 million. The excess cost over book value of the shares purchased was applied to retained earnings.

As at November 4, 2003, the Company has purchased a total of 2,434,800 common shares for a total cost of $125 million.

Dividend policy

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

Stock options

	Nine months ended September 30, 2003		
	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**12,882**	**$**	**37.13**
Granted	**480**	**$**	**51.39**
Exercised for common shares	**(2,503)**	**$**	**33.14**
Surrendered for cash settlement	**(501)**	**$**	**33.64**
Forfeited	**(502)**	**$**	**42.97**
Outstanding – end of period	**9,856**	**$**	**38.67**
Exercisable – end of period	**2,913**	**$**	**34.45**

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 nine months ended September 30, 2003, the Company recorded compensation expense of $137 million. As at September 30, 2003, the total liability for expected cash settlements under the Option Plan is $124 million, of which $104 million is included as a current liability. As at September 30, 2003, cash payments of $10 million had been made for 501,208 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.

		September 30, 2003
Balance – beginning of period	**$**	**24**
Unrealized loss on translation of net investment		**(125)**
Hedge of net investment with US dollar denominated debt (net of tax)		**110**
Balance – end of period	**$**	**9**

8. NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS PER COMMON SHARE

	Three Months Ended				Nine Months Ended			
Weighted average common shares outstanding (thousands)		**Sep 30 2003**		Sep 30 2002		**Sep 30 2003**		Sep 30 2002
Basic		**134,756**		133,201		**134,335**		125,950
Effect of dilutive stock options [(1)]		**-**		3,507		**1,630**		3,095
Assumed settlement of preferred securities with common shares [(2)]		**1,994**		-		**2,113**		2,609
Diluted		**136,750**		136,708		**138,078**		131,654
Net earnings attributable to common shareholders	**$**	**203**	$	117	**$**	**1,156**	$	361
Dividend on preferred securities (net of tax) [(2)]		**1**		-		**4**		5
Revaluation of preferred securities (net of tax) [(2)]		**-**		-		**(14)**		-
Diluted net earnings attributable to common shareholders	**$**	**204**	$	117	**$**	**1,146**	$	366
Net earnings per common share attributable to common shareholders								
Basic	**$**	**1.51**	$	0.88	**$**	**8.61**	$	2.87
Diluted	**$**	**1.49**	$	0.86	**$**	**8.30**	$	2.78

[(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.

[(2)] Preferred securities were anti-dilutive for the three months ended September 30, 2002 but were dilutive for the nine months ended September 30, 2002.

9. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended		Nine Months Ended	
	Sep 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Interest paid	**$ 45**	$ 57	**$ 147**	$ 104
Taxes paid	**$ 26**	$ 29	**$ 27**	$ 93

10. FINANCIAL INSTRUMENTS

The Company uses certain derivative financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The Company has the following financial derivatives outstanding as at November 4, 2003:

	Remaining Term		Volume	Average Price	*Index*
Oil					
Brent differential swaps	Oct 2003 –	Dec 2003	15,000 bbls/d	US $1.00	Dated Brent/WTI
	Jan 2004 –	Dec 2004	40,000 bbls/d	US $1.22	Dated Brent/WTI
Oil price collars	Oct 2003 –	Dec 2003	125,000 bbls/d	US $25.56 – US $31.37	WTI
	Jan 2004 –	Mar 2004	125,000 bbls/d	US $25.24 – US $30.86	WTI
	Apr 2004 –	Jun 2004	90,000 bbls/d	US $24.67 – US $29.53	WTI
	Jul 2004 –	Sep 2004	30,000 bbls/d	US $24.50 – US $29.78	WTI

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

	Remaining Term	Amount ($ millions)	Average Exchange Rate (US $/Cdn $)
Foreign currency			
Currency collars	Oct 2003 – Aug 2004	US $25/month	1.51 – 1.59
	Jan 2004 – Dec 2004	US $ 3/month	1.45 – 1.54
	Oct 2003 – Aug 2005	US $10/month	1.37 – 1.49

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

	Remaining Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest rate				
Swaps – fixed to floating	Oct 2003 – Jul 2004	US $200	6.70%	LIBOR + 2.09%
	Oct 2003 – Jul 2006	US $200	6.70%	LIBOR + 1.58%
	Oct 2003 – Jan 2005	US $200	7.20%	LIBOR + 3.00%
	Oct 2003 – Jan 2007	US $200	7.20%	LIBOR + 2.23%
	Oct 2003 – Oct 2012	US $350	5.45%	LIBOR + 0.81%
Swaps – floating to fixed	Oct 2003 – Mar 2004	Cdn $100	5.08%	CDOR (1)
	Oct 2003 – Mar 2007	Cdn $ 16	7.36%	CDOR

(1) *The Company unwound this swap subsequent to September 30, 2003.*

11. COMMITMENTS

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

12. SEGMENTED INFORMATION

	Three Months Ended		Nine Months Ended	
	Sep 30 2003	Sep 30 2002	**Sep 30 2003**	Sep 30 2002
Revenue				
North America	**$ 1,080**	$ 937	**$ 3,556**	$ 2,260
North Sea	**232**	187	**705**	385
Offshore West Africa	**46**	36	**106**	71
Midstream	**13**	13	**45**	37
	$ 1,371	$ 1,173	**$ 4,412**	$ 2,753
Net Earnings				
North America	**$ 148**	$ 113	**$ 990**	$ 388
North Sea	**36**	-	**105**	(20)
Offshore West Africa	**15**	7	**32**	(15)
Midstream	**5**	5	**19**	13
	204	125	**1,146**	366
Dividend on preferred securities (net of tax)	**(1)**	(2)	**(4)**	(5)
Revaluation of preferred securities (net of tax)	**-**	(6)	**14**	-
Net Earnings Attributable to Common Shareholders	**$ 203**	$ 117	**$ 1,156**	$ 361
Additions to Property, Plant and Equipment				
North America	**$ 407**	$ 307	**$ 1,338**	$ 902
North Sea	**109**	288	**257**	243
Offshore West Africa	**53**	57	**129**	169
Horizon Oil Sands Project	**32**	10	**100**	49
Midstream	**5**	-	**9**	15
Abandonments	**14**	20	**20**	39
Head office	**10**	4	**15**	7
	$ 630	$ 686	**$ 1,868**	$ 1,424

	Property, Plant and Equipment		Total Assets	
	Sep 30 2003	Dec 31 2002	**Sep 30 2003**	Dec 31 2002
Segmented Assets				
North America	**$ 10,701**	$ 10,252	**$ 11,362**	$ 10,917
North Sea	**1,121**	1,277	**1,261**	1,427
Offshore West Africa	**621**	518	**667**	549
Horizon Oil Sands Project	**329**	229	**329**	229
Midstream	**199**	196	**224**	209
Head office	**36**	28	**36**	28
	$ 13,007	$ 12,500	**$ 13,879**	$ 13,359

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated August 1, 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 September 30, 2003:

Interest coverage (times)	
Net earnings	11.2 [(1)]
Cash flow from operations attributable to common shareholders	19.5 [(2)]

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

The interest coverage ratios have been calculated without including the annual carrying charges relating to the outstanding preferred securities of the Company. If the preferred securities were classified as long-term debt, these annual carrying charges would be included in interest. If these annual carrying charges had been included in the calculations, the net earnings coverage ratio for the 12-month period ended September 30, 2003, would be 10.8x and the cash flow coverage ratio for the 12-month period ended September 30, 2003 would be 18.5x.

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, November 5, 2003. The North American conference call number is 1-800-818-6210 and the outside North America conference call number is 1-416-641-6452. Please call in about 10 minutes before the starting time in order to be patched into the call. Should you experience difficulty in connecting to the call, those in North America should please call 1-800-473-0602. Those outside North America should please call 1-905-502-3723. Media are invited to participate in listen-only mode.

Replay: A taped rebroadcast will be available until Wednesday, November 12, inclusive. To access postview in North America, dial 1-800-558-5253 and enter the passcode 21159577. Those outside of North America dial 1-416-626-4100 and enter the passcode number 21159577.

2003 FOURTH QUARTER AND YEAR END RESULTS

2003 fourth quarter and year end results are scheduled for release Wednesday, February 25, 2004. A conference call will be held on that day at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time.

For further information, please contact:

CANADIAN NATURAL RESOURCES LIMITED
2500, 855 – 2nd Street S.W.
Calgary, Alberta
T2P 4J8

Telephone: (403) 514-7777
Facsimile: (403) 517-7370
Email: investor.relations@cnrl.com
Website: www.cnrl.com

Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange

ALLAN P. MARKIN
Chairman

JOHN G. LANGILLE
President

STEVE W. LAUT
Chief Operating Officer

COREY B. BIEBER
Director
Investor Relations