CANADIAN NATURAL RESOURCES LIMITED

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2002 FOURTH QUARTER RESULTS

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CANADIAN NATURAL ANNOUNCES RECORD ANNUAL CASH FLOWS FOR 2002 YEAR END

In commenting on fourth quarter and year-end 2002 results, Canadian Natural's Chairman, Allan Markin, stated "Last year was another important and positive step in the evolution of Canadian Natural. The year was marked by impressive growth, a continued strong balance sheet, record annual cash flows, and a portfolio which struck a balance between oil and natural gas. The project portfolio is deep in each of our product offerings and resource basins and we now operate and control virtually all of our assets around the world. Through execution of our strategies we have developed into the 'Premium Value, Defined Growth Independent'."

"We are very pleased with our production results for 2002. Our 2002 volumes were about 17% higher than 2001 with the majority of that growth coming from natural gas. Proved reserves similarly increased by about 20% year over year. During 2002, in two major transactions we increased our natural gas production through the Rio Alto acquisition, gaining a new high potential core natural gas area in the process, and, through a number of acquisitions, consolidated ownership interests and operatorship in the North Sea. During the year we also brought one major international development on-stream, announced a second major international development project, announced a high potential international exploration concession and formalized our in-situ development plans. We also made our formal application to the Alberta Government for approval to develop our Horizon Oil Sands Project."

"We are well positioned to deliver continued growth and robust returns into 2003 and beyond. We expect current year production to grow by about 10% over 2002 levels, with the majority of that growth coming from conventional heavy oil drilling in North America and light oil in the North Sea and Offshore West Africa. In North America we will complete our set-up drilling program in our new Northwest Alberta natural gas area in order to establish the groundwork for an aggressive 2004 drilling program in this area. We will also commence drilling of new high-pressure wells at our Primrose in-situ play, which will yield higher incremental production in 2004."

"The ability to generate superior cash flow remains the foundation of the Company's success, and we proved our ability during the fourth quarter by reducing net debt by $446 million. Our confidence in cash flow generation capability has also resulted in our Board of Directors declaring a 20% increase in our dividend to $0.60 per common share per annum. Based upon our budgeted 2003 oil pricing of US $24 WTI per barrel and natural gas pricing of US $4.00 NYMEX per mmbtu, Canadian Natural continues to generate significant free cash flow, which will enable us to spend over $800 million in 2003 on future oriented growth projects while still reducing long-term indebtedness. Today's commodity pricing is well in excess of our budgeted price-deck for each of our products, resulting in potential 2003 cash flows in excess of $3.5 billion. We will use the majority of this excess free cash flow to repay outstanding indebtedness, with portions to be allocated to our share buy-back program and additional capital spending in the latter half of the year."

HIGHLIGHTS

- Cash flow reached $2.3 billion ($17.63 per common share) a 17% increase over the $1.9 billion ($15.83 per common share) realized in 2001. Fourth quarter cash flow was $777 million ($5.81 per common share), an increase of $133 million over the previous record of $644 million recorded during the third quarter of 2002.

- Net earnings grew from $117 million ($0.88 per common share) in the third quarter to $208 million ($1.56 per common share) in the fourth quarter of 2002 while net earnings for the year amounted to $570 million ($4.46 per common share) compared with $643 million ($5.30 per common share) earned in 2001.

- Third straight year of quarterly dividend increases. The 2003 quarterly dividends will increase by 20% from $0.125 per common share to $0.15 per common share commencing with the April 1, 2003 dividend payment.

- Annual natural gas sales volumes of 1,232 million cubic feet per day, an increase of 34% from 2001 levels. Fourth quarter natural gas sales volumes amounted to 1,365 million cubic feet per day.

- Annual oil and liquids sales volumes of 215.3 thousand barrels per day, an increase of 4% over 2001 levels. Fourth quarter oil and liquids sales volumes were 240.6 thousand barrels per day.

- In the fourth quarter of 2002, realized cash flow well in excess of capital expenditures of $292 million resulted in a net debt repayment in the fourth quarter of $446 million.

- Realized a 46% increase in the wellhead price for oil and liquids sales over the corresponding quarter of 2001, as a result of higher world oil prices and lower heavy oil price differentials for heavy oil production. Similarly, the Company realized a 70% increase in the wellhead price for its natural gas over the corresponding quarter of 2001.

- Proved and probable reserve additions equalled 301% of 2002 production (263% using only proved reserves), at a finding, development and on stream cost of $8.47 per barrel of oil equivalent ($9.70 per barrel of oil equivalent using only proved reserves). Achieved natural gas reserve additions of close to 1 trillion cubic feet (0.9 trillion cubic feet of proved reserves), bringing total natural gas reserves to 3.7 trillion cubic feet, 94% of which are located in North America.

- Total proved Company gross reserves at the end of 2002 amounted to 961 million barrels of oil and liquids and 3.2 trillion cubic feet of natural gas (1.5 billion barrels of oil equivalent) with additional probable reserves of 220 million barrels of oil and liquids and 0.5 trillion cubic feet of natural gas. These reserves exclude 6 billion barrels of recoverable bitumen reserves from the Horizon Oil Sands Project.

- Year-end proved and probable reserves per common share increased over 2001 levels by 6% for natural gas and 11% for oil and liquids.

- Successfully completed the acquisition of additional interests in the North Sea and the transition to operator of four producing platforms in the North Sea. Based upon cash flow realized since the acquisition and future strip pricing, cash flow from the properties acquired is expected to pay out the cash cost of the acquisition by the end of the second quarter of 2003.

- In January 2003, extended for an additional 12-month period our Normal Course Issuer Bid through the facilities of The Toronto Stock Exchange and the New York Stock Exchange for the purchase of up to 5% of our outstanding common shares or 6.7 million common shares at the market price if and when acquired. To date the Company has purchased 175,600 common shares under this program.

- Trailing 12-month after tax return on average common shareholders' equity amounted to 14% and after tax return on capital employed was 9%. Consistent with prior years, EBITDA return on capital employed remained at 34% and cash flow return on capital employed attained 30%.

OPERATIONS REVIEW

Production

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

Natural gas continues to represent Canadian Natural's largest product offering with annual production of 1,232 mmcf/d, an increase of 34% over 2001 annual production volumes. Fourth quarter natural gas production averaged 1,365 mmcf/d, an increase of 35% over the corresponding period of 2001, primarily reflecting the mid-year acquisition of Rio Alto Exploration Ltd. ("Rio Alto"). Fourth quarter production was down 62 mmcf/d from third quarter production levels of 1,427 mmcf/d, primarily reflecting the steep declines from the Ladyfern field in Northeast British Columbia. Ladyfern production declined from an average of 178 mmcf/d in the third quarter of 2002 to 127 mmcf/d during the fourth quarter of 2002. The Company expects this field to continue declines in the order of 70% through 2003, with current production approximating 80 mmcf/d. The Ladyfern field is not representative of typical natural gas pools both due to its overall size and its production profile of very high production volumes with a very rapid decline. Typical natural gas decline rates approximate 23% for other natural gas fields owned by the Company.

Production of oil and liquids during 2002 averaged 215.3 mbbls/d compared with 206.3 mbbls/d in 2001. Production during the fourth quarter of 2002 was 1.5 mbbls/d lower than the previous quarter but 42.6 mbbls/d higher than the corresponding period of last year. Annual increases in North America reflected additional heavy oil drilling activity and acquired production. North Sea volumes increased primarily as a result of the acquisition of additional interests to consolidate the Company's position in the northern sector of the North Sea. Offshore West Africa volumes increased as production was brought on-stream at the Espoir field.

The Company's production composition is as follows:

	Q4 2002		Q3 2002		Q4 2001	
	mboe/d	*%*	*mboe/d*	*%*	*mboe/d*	*%*
Natural gas	**227.5**	**49**	237.9	50	168.6	46
Light oil and NGLs	**104.7**	**22**	102.8	21	74.5	20
Pelican Lake oil	**28.6**	**6**	32.0	7	30.8	9
Primary heavy oil	**68.5**	**15**	66.9	14	53.2	14
Thermal heavy oil	**38.8**	**8**	40.3	8	39.5	11
	468.1	**100**	479.9	100	366.6	100

The Company expects production levels in 2003 to average 1,280 to 1,330 mmcf/d of natural gas and 240 to 260 mbbls/d of oil and liquids, unchanged from previous expectations. First quarter 2003 production guidance for natural gas is 1,300 to 1,320 mmcf/d of natural gas and 235 to 240 mbbls/d of oil and liquids. Current production levels are approximately 1,315 mmcf/d of natural gas and 238 mbbls/d of oil and liquids. Further detailed guidance on production levels and operating costs may be found on the Company's website.

http://www.cnrl.com/investor/guidance.htm

DRILLING ACTIVITY *(number of wells)*

	YEAR ENDED DECEMBER 31			
	2002		2001	
	Gross	**Net**	**Gross**	**Net**
Oil	316	264	270	231
Natural gas	183	162	576	476
Dry	32	27	36	32
Subtotal	531	453	882	739
Injection/strat tests	456	447	356	353
Total	987	900	1,238	1,092
Success rate *(excluding injection/strat tests)*		94%		96%

Canadian Natural pursued a modest drilling program in the fourth quarter of 2002 with the drilling of 11 net oil wells and 12 net natural gas wells. These wells were spread across the Company's five North American core regions as well as in the North Sea and Offshore West Africa. The total success rate for Canadian Natural's drilling program was 85% during the fourth quarter, excluding injection/stratigraphic test wells.

The number of net wells drilled during the year (excluding injection/stratigraphic test wells) decreased 39% from the prior year, comprised of a 66% reduction in natural gas well drilling and a 14% increase in oil well drilling. The decrease in natural gas drilling reflects the Company's decision to defer natural gas drilling from 2002 to 2003 to offset anticipated Ladyfern production declines.

During the year, the Company drilled 441 net stratigraphic test wells on the oil sands leases in the Horizon Oil Sands Project and in North Alberta/West Saskatchewan.

Pricing

Netbacks for the Company's natural gas production improved during the fourth quarter when compared with the previous quarter. During the third quarter of 2002 natural gas pricing in Canada was subject to abnormally high differentials to NYMEX benchmark pricing. This high differential was the result of common carrier third quarter pipeline maintenance activities and its subsequent impact on exports of natural gas to the United States.

Netbacks received for Canadian Natural's heavy oil and Pelican Lake oil production remained strong despite seasonal increases of price differentials to WTI. Differentials remain lower than normal based upon the historical ratio of quality differential to WTI pricing due to lower supply from Western Canadian producers. Canadian Natural expects heavy oil pricing to remain above long-term averages for the next few months, reflecting both high WTI pricing resulting from general market uncertainty and reduced heavy oil supplies.

In 2003, as part of its overall risk management program, the Company has placed costless collars on a portion of its oil and natural gas production. These financial instruments are summarized in note 8 to the consolidated financial statements.

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

		Pricing Indications as at Feb 21, 2003		**Q4 2002**		**Q3 2002**		**Q4 2001**
WTI benchmark price *(US $/bbl)*	**$**	**35.58**	**$**	**28.17**	$	28.25	$	20.49
Differential to LLB blend *(US $/bbl)*	**$**	**9.87**	**$**	**8.13**	$	5.97	$	10.07
Condensate benchmark price *(US $/bbl)*	**$**	**36.17**	**$**	**28.56**	$	28.14	$	19.64
NYMEX benchmark price *(US $/mmbtu)*	**$**	**6.61**	**$**	**3.99**	$	3.26	$	2.50
AECO benchmark price *(Cdn $/mmbtu)*	**$**	**10.56**	**$**	**5.25**	$	3.25	$	3.30
Canadian Natural's Wellhead Price(1)								
Light oil and NGLs *(Cdn $/bbl)*	**$**	**44.98**	**$**	**36.08**	$	34.36	$	29.42
Pelican Lake oil *(Cdn $/bbl)*	**$**	**33.25**	**$**	**25.30**	$	30.58	$	17.40
Primary heavy oil *(Cdn $/bbl)*	**$**	**32.22**	**$**	**24.78**	$	30.11	$	15.77
Thermal heavy oil *(Cdn $/bbl)*	**$**	**31.85**	**$**	**24.11**	$	29.23	$	13.59
Natural gas *(Cdn $/mcf)*	**$**	**9.27**	**$**	**5.04**	$	3.15	$	2.94

(1) *Including financial instruments.*

ACTIVITY BY CORE REGION

	Net Undeveloped Land As at December 31, 2002 *(thousands of net acres)*	**Drilling Activity Year ended December 31, 2002** *(net wells)*
Northeast British Columbia	**1,513**	48
Northwest Alberta	**1,821**	13
North Alberta/West Saskatchewan	**5,935**	475
Horizon Oil Sands Project	**117**	293
South Alberta	**666**	55
Southeast Saskatchewan	**161**	5
United Kingdom North Sea	**410**	6
Offshore West Africa	**943**	5

North America Conventional

As a result of large Ladyfern production increases during the first half of 2002, Canadian Natural reduced natural gas drilling activity with a view to building prospect inventories in anticipation of expected high Ladyfern declines. The Ladyfern pool in Northeast British Columbia has been a tremendous success for Canadian Natural. Production ramped up very quickly and the pool is being depleted in a quick, orderly fashion. Ladyfern is a rare pool and difficult to replicate.

The acquisition of Rio Alto provided Canadian Natural with a high quality natural gas producing base as well as a new core area in Northwest Alberta with extensive opportunities on a large undeveloped land base. The undeveloped land contains multiple zones for natural gas production supported by a large amount of seismic data and pipeline and natural gas plant infrastructure. Canadian Natural commenced development of this land in the first quarter of 2003 with the drilling of up to a total of 65 wells in 2003. The majority of these wells will be drilled in the northern section of the core area, where the Cretaceous geological features are very similar to Canadian Natural's North Alberta core area. Approximately 17 wells will target the southern portion and the Cardium zone which is a complex geological zone requiring both horizontal and vertical wells to test the production capabilities of the formation. Canadian Natural is utilizing 2003 to test and develop new geological theories on best practices for exploitation of the Cardium zone. This will encompass the reprocessing and interpretation of new and existing seismic as well as limited use of vertical and horizontal drilling techniques to determine the optimal approaches to various Cardium play types. This organized and methodical approach will lead to an expanded and more cost effective drilling campaign in 2004 and beyond.

During 2002 Canadian Natural drastically reduced the number of natural gas wells drilled from the 476 net natural gas wells drilled in 2001. The Company's natural gas drilling program will be expanded in 2003 with the planned drilling of 580 wells on lands with natural gas potential. Approximately 240 of the wells will be drilled in the first quarter on lands with winter only access. The remainder of the well program, including approximately 250 southern Alberta shallow wells, are scheduled for lands with year round access that can be drilled throughout the year. The 2003 drilling program is on track and progressing according to expectations.

The experimental Pelican Lake emulsion flood began injections in early April 2002 and injections continued during the fourth quarter. Indications to date suggest that the recovery mechanism is very efficient, resulting in slower response time. Canadian Natural will work to maximize the value of the Enhanced Oil Recovery scheme by finding the optimal balance between response time and recovery factors. To this end, an observation well will be drilled in the first quarter of 2003 to assess the effectiveness of the injection to date. The Company will also be implementing a demonstration scale waterflood project to evaluate this secondary recovery technique, which should increase response time. If either project is successful, the recovery factor from the Pelican Lake sands will increase substantially. This field contains approximately three billion barrels of original oil-in-place but is only expected to achieve a 6% recovery factor using primary technologies.

Following regulatory approval in 2002 to utilize high pressure steaming at its thermal oil project at Primrose in eastern Alberta, Canadian Natural will develop and in 2003 drill new pads containing a total of 48 wells incorporating high pressure steaming. Steaming of these wells will commence in the third quarter of 2003 with initial oil production following in mid 2004.

Horizon Oil Sands Project

The Horizon Oil Sands Project ("Horizon Project") is situated on leases containing over 6 billion barrels of mineable oil reserves, supporting a three-phase development that will produce 232 mbbls/d of light sweet crude oil for over 40 years. The Horizon Project encompasses four operational segments: minesite, extraction, primary upgrading and secondary upgrading. Additional development potential also exists on the leases to extract a further 2 billion barrels of mineable reserves and 1 billion barrels of in-situ reserves.

Canadian Natural believes that certainty of long-term costs and implementation consistency is required prior to the final commitment for an investment as large as the Horizon Project. The Canadian Government's ratification of the Kyoto Protocol in the last quarter of 2002 has resulted in a decrease in cost certainty. Recently the Federal Government has provided some limits to the cost of Kyoto implementation through 2012; however, beyond 2012 no implementation certainty exists. As the Horizon Project is scheduled to commence production in 2008 and produce for over 40 years, the lack of clarity on Kyoto implementation over the long-term precludes Canadian Natural's ability to commit to the construction of the Horizon Project at this time.

Canadian Natural anticipates completion of its Design Basis Memorandum ("DBM") phase of engineering in the first quarter of 2003. Although sufficient levels of implementation certainty to start construction do not exist today, Canadian Natural anticipates such levels of certainty will be achieved, and therefore has decided to continue with the Engineering Design Specification ("EDS") phase of engineering. The EDS will commence after completion of the DBM with related 2003 expenditures included in the Company's current Horizon Project budget of $211 million.

Canadian Natural will continue to work with the Federal Government to obtain long-term certainty on costs over the life of the Horizon Project before any site clearing or pre-construction work begins in 2004. Depending upon the results of this undertaking, Canadian Natural will then evaluate two potential outcomes - completion of the Horizon Project in Ft. McMurray, with complete upgrading on-site; or completion of the Horizon Project in Ft. McMurray, with secondary upgrading facilities relocated to the United States.

Canadian Natural anticipates receiving regulatory approvals for the Horizon Project from the Alberta Energy Utility Board in late 2003. The Company would be in a position to commence site clearing and pre-construction in 2004, with full construction commencing upon achieving a targeted 80% completion of detailed engineering and design. The first phase of the Horizon Project would then be commissioned in 2008 at 110 mbbls/d of light synthetic crude oil. Phase two would be commissioned in 2010, increasing production to 155 mbbls/d of production. Phase three would be completed in 2012, bringing total production to 232 mbbls/d. The Company's leases could support further expansions beyond that date.

United Kingdom

During the fourth quarter Canadian Natural assumed operatorship of the Ninian, Murchison and Lyell fields in the northern North Sea. To facilitate efficient management of its North Sea operations, Canadian Natural has relocated the majority of its UK operations to Aberdeen during the fourth quarter, with remaining portions expected to transition during 2003.

In December, a third producing well was completed at the non-operated Banff field, with initial production rates of 5,500 bbls/d of oil net to Canadian Natural. The Company had expected this well to come on stream in early November. In addition, one well at the Columba B field was brought on production in mid-December at approximately 6,500 bbls/d of oil net to the Company. It is anticipated that this well will be converted to a water injection well when the production declines below its economic limit.

In 2003, Canadian Natural has budgeted to spend a total of $283 million on its international holdings in the United Kingdom. These funds will be directed towards drilling an additional 18 wells in the North Sea. Other exploitation and waterflood optimization programs will also be carried out in both the northern and central areas to increase the productivity and recovery factors in these known pools of light oil.

During February 2003, the Ninian South platform's regularly scheduled three day maintenance shut down was extended for a period of two weeks for additional required maintenance, temporarily impacting production from portions of the Ninian field as well as the Columbas' Terraces and Lyell fields. This two-week shut down will eliminate the need for the major maintenance program previously scheduled for June 2003. Prior to taking over operatorship of four platforms in the northern North Sea, Canadian Natural recognized the need for additional maintenance expenditures in 2003. The original maintenance timing remains in effect for the other three platforms (Ninian Central, Ninian North, and Murchison), also acquired in 2002.

Offshore West Africa

During the quarter, Canadian Natural continued the development of the 59% owned and operated Espoir field located offshore Côte d'Ivoire. Production continued from three producing wells supported by two water injection wells. Unanticipated faults and hole stability issues encountered in the drilling of a well which was spud last August has resulted in drilling program delays. The offshore development will continue with two water injection wells and one producing well scheduled for drilling and completion at East Espoir during the first half of 2003. These injectors will enhance the build up of pressures in the upper zones of the oil reservoir, which are scheduled for perforation by mid-2003, providing up to 5,000 bbls/d of additional net oil production. During December 2002 a satellite pool, Emien, was drilled, but encountered no hydrocarbons. The Company anticipates drilling a second, larger satellite pool, Acajou, during the first half of 2003.

Canadian Natural also continued with development plans on the Baobab field located offshore Côte d'Ivoire. The development continues for first oil planned at initial oil production rates of 45,000 bbls/d in 2005, increasing with full development to 60,000 bbls/d. Several components of the subsea infrastructure and the floating production storage and offtake vessel are currently out to bid. This field contains approximately 200 million barrels of recoverable reserves and is operated and 61% owned by Canadian Natural. Field development plans were approved by the Government of Côte d'Ivoire in December 2002.

Canadian Natural's offshore development activities in Côte d'Ivoire remain unaffected by recent political insurrection in the country. The Company has established back up facilities in a neighbouring country to ensure operations are not affected should conditions significantly deteriorate. To date, Canadian Natural has not needed to utilize this contingency.

Canadian Natural's 2003 capital budget forecasts expenditures totalling $280 million in Offshore West Africa. In Côte d'Ivoire the Company will complete the drilling and completion operations at Espoir, drill an exploration well at Acajou, and finalize the Baobab development plans with development drilling commencing in the fourth quarter. The Company also plans on drilling one of two identified prospects on its Block 16 exploration acreage located offshore Angola during the second half of 2003. This high-risk/high-potential exploration block in which Canadian Natural is the operator with a 50% interest is located in one of the world's most prolific oil basins.

YEAR END RESERVES

Canadian Natural retains independent petroleum engineering consultants, Sproule Associates Limited ("Sproule"), to evaluate the Company's proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. The independent evaluator's reports covered 89% of the Company's reserves with the Company internally evaluating the remaining 11%, which are generally comprised of reserves in properties not currently strategic to the Company's core business areas. The Board of Directors of the Company has a Reserve Committee, which has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

During 2002 Canadian Natural replaced 301% of its production and increased reserves per common share by 10%. Including the mid-year acquisition of Rio Alto, natural gas reserve additions totalled 218% of production, despite a 66% reduction in natural gas drilling. Oil and liquids replacement ratios were 380%, reflecting an expanded heavy oil drilling program in Canada, property acquisitions in the North Sea and additional drilling success Offshore West Africa.

Canadian Natural's strategy of exploitation coupled with exploration and opportunistic acquisitions continues to be very successful. The Company has increased its reserves per common share in every year of its existence, with 2003 results being an 11% increase in oil reserves to 8.8 barrels per common share and a 6% increase in natural gas reserves to 27.4 mcf per common share. The reserve mix on a boe basis is also showing more balance with natural gas reserves remaining constant at 34% of total reserves, light oil reserves increasing to 32% of total reserves from 23% of total reserves and heavy oil reserves decreasing to 34% of total reserves from 43% of total reserves.

No reserves have been assigned by the Company or Sproule to the Horizon Oil Sands Project. Canadian Natural's internal estimate of recoverable reserves is 6 billion barrels of bitumen. Canadian Natural owns 100% of these estimated reserves with production scheduled to commence in 2008.

Canadian Natural's reserves before royalties are summarized in the following tables:

DECEMBER 31, 2002	Proved Developed	Proved Undeveloped	Proved Total	Probable	Total
Oil & Liquids *(mmbbls)*					
North America	396	269	665	77	742
North Sea	104	96	200	73	273
Offshore West Africa	33	63	96	70	166
	533	428	961	220	1,181
Natural gas *(bcf)*					
North America	2,721	327	3,048	402	3,450
North Sea	56	15	71	18	89
Offshore West Africa	33	57	90	31	121
	2,810	399	3,209	451	3,660
Total Reserves *(mmboe 6:1)*	1,001	495	1,496	295	1,791
Present value of reserves *($ millions)*[1][2]					
10% discount	$ 10,967	$ 1,811	$ 12,778	$ 1,038	$ 13,816

DECEMBER 31, 2001	Proved Developed	Proved Undeveloped	Proved Total	Probable	Total
Oil & Liquids *(mmbbls)*					
North America	382	262	644	95	739
North Sea	54	31	85	23	108
Offshore West Africa	21	40	61	51	112
	457	333	790	169	959
Natural gas *(bcf)*					
North America	2,288	278	2,566	349	2,915
North Sea	19	75	94	24	118
Offshore West Africa	17	52	69	27	96
	2,324	405	2,729	400	3,129
Total Reserves *(mmboe 6:1)*	845	400	1,245	236	1,481
Present value of reserves *($ millions)*[1][2]					
10% discount	$ 7,850	$ 1,699	$ 9,549	$ 847	$ 10,396

(1) *Excludes provisions for abandonment costs and income taxes.*
(2) *Value of the probable reserves is reduced by 50% to account for risk.*

RESERVES RECONCILIATION

	Oil and liquids *(mmbbls)*				Natural gas *(bcf)*			
Proved Reserves	**North America**	**North Sea**	**Offshore West Africa**	**Total**	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Proved Reserves, December 31, 2000	642	102	37	781	2,360	91	66	2,517
Discoveries and purchases	30	-	46	76	637	1	24	662
Property disposals	(1)	-	-	(1)	(25)	-	-	(25)
Production	(61)	(13)	(1)	(75)	(331)	(4)	-	(335)
Revisions of prior estimates	34	(4)	(21)	9	(75)	6	(21)	(90)
Proved Reserves, December 31, 2001	644	85	61	790	2,566	94	69	2,729
Discoveries and purchases	**66**	**113**	**18**	**197**	**951**	**18**	**5**	**974**
Property disposals	**(1)**	**(18)**	**-**	**(19)**	**(4)**	**(56)**	**-**	**(60)**
Production	**(62)**	**(14)**	**(3)**	**(79)**	**(439)**	**(10)**	**(1)**	**(450)**
Revisions of prior estimates	**18**	**34**	**20**	**72**	**(26)**	**25**	**17**	**16**
Proved Reserves, December 31, 2002	**665**	**200**	**96**	**961**	**3,048**	**71**	**90**	**3,209**
Probable Reserves (Unrisked)								
Probable Reserves, December 31, 2000	88	33	9	130	402	23	19	444
Discoveries and purchases	-	(1)	19	18	32	(1)	11	42
Property disposals	-	-	-	-	(6)	-	-	(6)
Revisions of prior estimates	7	(9)	23	21	(79)	2	(3)	(80)
Probable Reserves, December 31, 2001	95	23	51	169	349	24	27	400
Discoveries and purchases	10	23	(14)	19	89	6	(17)	78
Property disposals	-	(4)	-	(4)	-	(6)	-	(6)
Revisions of prior estimates	(28)	31	33	36	(36)	(6)	21	(21)
Probable Reserves, December 31, 2002	77	73	70	220	402	18	31	451
Proved & Probable Reserves,								
December 31, 2001	739	108	112	959	2,915	118	96	3,129
December 31, 2002	**742**	**273**	**166**	**1,181**	**3,450**	**89**	**121**	**3,660**

Future oil and natural gas price forecasts used in the Evaluation Reports were based on Sproule's December 31, 2002 pricing model and adjusted for quality of reserves and transportation. The prices used for the subsequent five years in the Evaluation Reports are as follows:

YEAR	Oil				Natural Gas			
	Company Average Price Cdn$/bbl	WTI At Cushing Oklahoma US$/bbl	Hardisty Heavy 12 API Cdn$/bbl	Brent UK US$/bbl	Company Average Price Cdn$/mcf	Henry Hub Louisiana US$/mmbtu	Alberta AECO Cdn$/mmbtu	British Columbia Plantgate Cdn$/mmbtu
	As at December 31, 2002							
2003	30.59	25.99	25.92	24.49	5.73	4.39	5.89	5.94
2004	27.91	23.60	23.78	22.08	5.22	4.05	5.38	5.43
2005	25.18	21.63	21.16	20.09	4.62	3.61	4.77	4.82
2006	25.48	21.96	21.83	20.39	4.31	3.40	4.45	4.48
2007	26.22	22.29	22.89	20.70	4.46	3.45	4.61	4.66
	As at December 31, 2001							
2002	18.36	19.90	14.41	18.40	3.80	2.89	3.80	3.75
2003	20.85	20.64	18.44	19.11	4.33	3.24	4.35	4.30
2004	23.44	21.12	21.58	19.29	4.32	3.25	4.36	4.26
2005	23.75	21.44	22.13	19.58	4.33	3.25	4.36	4.26
2006	24.01	21.76	22.62	19.87	4.42	3.29	4.44	4.34

FINDING AND DEVELOPMENT COSTS

	2002	2001	3 Year
Net reserve replacement expenditures *($ millions)*	3,928	1,745	8,475
Reserve additions *(mmboe 6:1)*			
Proved reserves	405	176	976
Proved plus probable reserves	464	207	1,123
On stream cost *($/boe)*			
Proved reserves	9.70	9.91	8.68
Proved plus probable reserves	8.47	8.43	7.55

CORPORATE

The Board of Directors of Canadian Natural has recently adopted certain changes to its committee structures and members. These changes will further strengthen Canadian Natural's adherence to effective corporate governance practices as established by the various regulatory bodies to which the Company is subject. In addition, effective immediately, Mr. Murray Edwards has been appointed Vice-Chairman of Canadian Natural. This recognizes Mr. Edwards' ongoing involvement in setting and implementing the strategic direction of the Company.

FINANCIAL REVIEW

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

During the fourth quarter of 2002, strong operational results and product pricing enabled the Company to repay approximately $446 million of net debt. Corporate debt to cash flow reduced to 1.8 times versus 2.3 times recorded last quarter, while debt to book capitalization improved to under 46% from over 47% recorded last quarter.

As at December 31, 2002, Canadian Natural had:

- Approximately $1.3 billion of available unused bank credit lines.
- Fixed/floating interest rate mix of 40%/60%.
- An overall average borrowing cost of approximately 5% for the fourth quarter of 2002 and 4.5% for the year 2002.
- 76% of borrowings are denominated in US dollars.
- Non-bank based borrowings amount to 76% of total long-term debt with an average maturity of 15.6 years.

The ratings for Canadian Natural's debt securities and its relationships with principal banks are extremely important to the Company as we continue to expand and grow. Hence, Company management will continually undertake to strengthen the balance sheet and financial position. Canadian Natural's debt securities are rated "Baa1" by Moody's Investor Services Inc., "BBB+" by Standard & Poors Corporation and "BBB(high)" by Dominion Bond Rating Services Limited.

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

In response to the expected demand for oil and natural gas, the related pricing and to protect capital expenditure programs, the Company has entered into several financial instruments to manage exposure to commodity price market volatility. The details of these positions are set out in note 8 to the consolidated financial statements. The Company will continue to actively pursue additional hedging opportunities.

The Board of Directors has declared a 20% increase in the regular quarterly dividend to $0.15 per common share or $0.60 per share per annum commencing with the dividend payment on April 1, 2003. This dividend will be payable to shareholders of record at the close of business on March 14, 2003.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations should be read in conjunction with the unaudited interim consolidated financial statements for the quarter and year ended December 31, 2002 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2001. All dollar amounts are referenced in Canadian dollars, except as noted otherwise.

Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

ACQUISITION

Effective July 1, 2002, the Company paid cash of $850.0 million and issued 10,008,218 common shares to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement. This was a major acquisition for the Company and significantly increased the Company's natural gas production in North America. The Rio Alto acquisition is included in the results of operations commencing July 1, 2002.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001[1]**	**DEC 31 2002**	**DEC 31 2001[1]**
FINANCIAL HIGHLIGHTS *($ millions, except per share amounts)*					
Revenue	**$ 1,330**	$ 1,173	$ 666	**$ 4,083**	$ 3,589
Cash flow from operations attributable to common shareholders[2]	**$ 777**	$ 644	$ 326	**$ 2,254**	$ 1,920
Per common share – basic	**$ 5.81**	$ 4.83	$ 2.69	**$ 17.63**	$ 15.83
– diluted	**$ 5.62**	$ 4.71	$ 2.65	**$ 16.99**	$ 15.23
Net earnings attributable to common shareholders[3]	**$ 208**	$ 117	$ 53	**$ 570**	$ 643
Per common share – basic	**$ 1.56**	$ 0.88	$ 0.44	**$ 4.46**	$ 5.30
– diluted	**$ 1.51**	$ 0.86	$ 0.43	**$ 4.31**	$ 5.17
Acquisition of Rio Alto[4]	**$ -**	$ 2,393	$ -	**$ 2,393**	$ -
Capital expenditures, net of dispositions	**$ 292**	$ 621	$ 530	**$ 1,676**	$ 1,885

(1) *Restated for change in accounting policy (see consolidated financial statements notes 1 and 2).*
(2) *After dividend on preferred securities.*
(3) *After dividend and revaluation of preferred securities.*
(4) *September 30, 2002 acquisition costs include adjustment to finalize purchase price allocation.*

Cash flow for the three months ended December 31, 2002 increased significantly from the three months ended September 30, 2002 to $777 million mainly due to higher natural gas prices. Cash flow for the three months ended December 31, 2002 increased from the same period in 2001 due to increased production volumes, higher product netbacks and increased revenue from the Company's midstream segment. Cash flow for the year ended December 31, 2002 amounted to nearly $2.3 billion, an increase of 17% from the prior year due to increased production volumes and increased oil and liquids prices offset by lower natural gas prices.

Net earnings for the three months ended December 31, 2002 were $208 million, an increase of 78% from $117 million in the third quarter of 2002, and a 292% increase over the $53 million earned for the three months ended December 31, 2001. The increased net earnings reflect the significant increases in cash flow discussed above. On a year over year basis, net earnings decreased from $643 million to $570 million due to the natural gas weighted acquisition of Rio Alto, higher depletion, depreciation and amortization costs and increased future income tax expense.

ANALYSIS OF QUARTERLY CHANGES IN REVENUE

	Oil and liquids	Natural gas	Midstream	Total
Quarterly Revenue *($ millions)*				
December 31, 2001	$ 387.9	$ 273.6	$ 4.9	$ 666.4
Price variance	55.1	12.1	-	67.2
Volume variance	(26.8)	5.2	-	(21.6)
Other variance	-	-	5.5	5.5
March 31, 2002	416.2	290.9	10.4	717.5
Price variance	65.2	60.1	-	125.3
Volume variance	6.8	10.1	-	16.9
Other variance	-	-	3.1	3.1
June 30, 2002	488.2	361.1	13.5	862.8
Price variance	117.6	(72.5)	-	45.1
Volume variance	142.6	122.3	-	264.9
Other variance	-	-	(0.2)	(0.2)
September 30, 2002	748.4	410.9	13.3	1,172.6
Price variance	**(56.5)**	**235.1**	**-**	**178.6**
Volume variance	**(4.5)**	**(17.9)**	**-**	**(22.4)**
Other variance	**-**	**-**	**1.5**	**1.5**
December 31, 2002	**$ 687.4**	**$ 628.1**	**$ 14.8**	**$ 1,330.3**

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**[1]	**DEC 31 2002**	**DEC 31 2001**[1]
OPERATING HIGHLIGHTS					
Oil and liquids *($/bbl, except daily production)*					
Daily production *(bbls/d)*	**240,596**	242,051	198,000	**215,335**	206,323
Sales price	**$ 31.10**	$ 33.57	$ 21.28	**$ 29.76**	$ 24.31
Royalties	**3.53**	3.56	1.41	**3.16**	2.17
Production expense	**9.10**	8.67	7.52	**8.45**	7.64
Netback	**$ 18.47**	$ 21.34	$ 12.35	**$ 18.15**	$ 14.50
Natural gas *($/mcf, except daily production)*					
Daily production *(mmcf/d)*	**1,365**	1,427	1,012	**1,232**	918
Sales price	**$ 5.00**	$ 3.13	$ 2.94	**$ 3.76**	$ 5.16
Royalties	**1.09**	0.67	0.62	**0.78**	1.25
Production expense	**0.57**	0.55	0.53	**0.57**	0.51
Netback	**$ 3.34**	$ 1.91	$ 1.79	**$ 2.41**	$ 3.40
Barrels of oil equivalent *($/boe, except daily production)*					
Daily production *(boe/d)*	**468,132**	479,949	366,594	**420,722**	359,347
Sales price	**$ 30.54**	$ 26.26	$ 19.62	**$ 26.25**	$ 27.15
Royalties	**4.98**	3.80	2.47	**3.91**	4.42
Production expense	**6.34**	6.01	5.53	**5.99**	5.69
Netback	**$ 19.22**	$ 16.45	$ 11.62	**$ 16.35**	$ 17.04

[1] *Restated for change in accounting policy (see consolidated financial statements note 1).*

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	SEP 30 2002	DEC 31 2001	DEC 31 2002	DEC 31 2001
DAILY PRODUCTION					
Oil and liquids *(bbls/d)*					
North America	**181,744**	185,990	159,000	**169,675**	166,675
North Sea	**51,478**	47,114	35,749	**38,876**	36,252
Offshore West Africa	**7,374**	8,947	3,251	**6,784**	3,396
Total	**240,596**	242,051	198,000	**215,335**	206,323
Natural gas *(mmcf/d)*					
North America	**1,331**	1,395	993	**1,204**	906
North Sea	**32**	29	19	**27**	12
Offshore West Africa	**2**	3	-	**1**	-
Total	**1,365**	1,427	1,012	**1,232**	918
Product mix					
Light oil and NGLs	**22.4%**	21.4%	20.3%	**20.8%**	20.7%
Pelican Lake oil	**6.1%**	6.7%	8.4%	**7.0%**	9.7%
Primary heavy oil	**14.6%**	13.9%	14.5%	**14.0%**	15.8%
Thermal heavy oil	**8.3%**	8.4%	10.8%	**9.4%**	11.2%
Natural gas	**48.6%**	49.6%	46.0%	**48.8%**	42.6%

Oil and liquids production increased for all segments from the comparable three month period in 2001 and the year ended December 31, 2001. The increase in North America segmented production is attributable to additional heavy oil drilling activity and property acquisitions in the Company's core operating areas. Oil and liquids production also increased due to the restoration of certain heavy oil production that had previously been curtailed in December 2001 as a result of declines in world oil prices and unusually high heavy oil differentials. North Sea oil production increased as a result of the acquisition of additional interests in the northern sector of the North Sea in 2002. Offshore West Africa oil production increased from the comparable periods in 2001 as a result of commencing production from the Company's operated Espoir field, located offshore Côte d'Ivoire, in February 2002.

Oil and liquids production for the fourth quarter of 2002 was on the lower end of the Company's guidance of 240 to 250 mbbls/d provided in the prior quarter. Oil and liquids production decreased 1.5 mbbls/d in the fourth quarter of 2002 from the previous quarter due mainly to a decrease in North American production resulting from reduced drilling activity and the timing of the steam cycles affecting the production of the Company's thermal heavy oil. This decrease was partially offset by increased oil production from new wells in the North Sea. Offshore West Africa oil production decreased from the prior quarter due to unscheduled maintenance down time and delays in initiating water injection in the Espoir field.

Natural gas continues to represent Canadian Natural's largest product offering, accounting for over 48% of the Company's total production. Fourth quarter 2002 production of natural gas was at the higher end of the Company's guidance of 1,350 to 1,365 mmcf/d provided in the previous quarter. Production of natural gas decreased from the third quarter 2002 primarily due to declines at the Ladyfern field in northeast British Columbia. Ladyfern production declined from an average of 178 mmcf/d in the third quarter of 2002 to 127 mmcf/d during the fourth quarter of 2002 as well pressures declined.

Natural gas production increased from the comparable periods in 2001 due to development of the Ladyfern field and the mid-year acquisition of Rio Alto. Natural gas production from Rio Alto properties averaged 376 mmcf/d over the last half of the year. The Ladyfern field averaged 168 mmcf/d of natural gas production during 2002, up from 40 mmcf/d in 2001. Natural gas production increased in the North Sea due to the acquisition of additional interests in the Banff and Kyle fields.

For 2003, oil and natural gas production is expected to grow in excess of 10% on a boe basis over 2002 volumes. The majority of this growth is expected from conventional heavy oil drilling in North America and increased light oil production from the North Sea and Offshore West Africa. North Sea oil production is expected to increase due to the drilling of 18 new wells in 2003, while Offshore West Africa oil production is expected to increase as a result of perforating the upper production formation and implementing a water injection scheme.

	THREE MONTHS ENDED			**YEAR ENDED**	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**	**DEC 31 2002**	**DEC 31 2001**
PRODUCT PRICES					
Oil and liquids *($/bbl)*					
North America	**$ 27.57**	$ 31.07	$ 18.59	**$ 27.04**	$ 21.00
North Sea	**$ 41.83**	$ 41.68	$ 33.39	**$ 39.79**	$ 38.66
Offshore West Africa	**$ 43.15**	$ 42.78	$ 19.56	**$ 40.10**	$ 33.57
Company average	**$ 31.10**	$ 33.57	$ 21.28	**$ 29.76**	$ 24.31
Natural gas *($/mcf)*					
North America	**$ 5.04**	$ 3.15	$ 2.94	**$ 3.78**	$ 5.19
North Sea	**$ 3.20**	$ 1.98	$ 3.00	**$ 2.75**	$ 2.51
Offshore West Africa	**$ 4.63**	$ 4.97	$ -	**$ 4.82**	$ -
Company average	**$ 5.00**	$ 3.13	$ 2.94	**$ 3.76**	$ 5.16
Percentage of revenue *(excluding midstream revenue)*					
Oil and liquids	**52.3%**	64.6%	58.6%	**58.1%**	51.5%
Natural gas	**47.7%**	35.4%	41.4%	**41.9%**	48.5%

Oil and liquids pricing realized by the Company is directly correlated with world oil pricing and heavy oil differentials. The realized oil and liquids price in the fourth quarter of 2002 was relatively stable with the prior quarter except in North America. The North American realized oil and liquids price for the three months ended December 31, 2002 decreased from the prior quarter due to the widening of heavy oil differentials caused by seasonal fluctuations. The fourth quarter 2002 price for oil and liquids was higher than in the same period in 2001 due to higher heavy oil differentials experienced in 2001 caused by the shutdown of a heavy oil refinery in the US mid-west and reduced demand for heavy oil. West Texas Intermediate averaged US $28.17 per bbl for the quarter ended December 31, 2002 compared to US $28.25 per bbl and US $20.49 per bbl for the quarters ended September 30, 2002 and December 31, 2001, respectively. Heavy oil differentials averaged US $8.13 per bbl for the quarter ended December 31, 2002 compared to US $5.97 per bbl and US $10.07 per bbl for the quarters ended September 30, 2002 and December 31, 2001, respectively.

North American natural gas prices increased in the quarter ended December 31, 2002 from the comparable three month periods due to higher AECO prices. AECO averaged $5.25 per mmbtu during the quarter ended December 31, 2002, up from $3.25 per mmbtu for the quarter ended September 30, 2002 and $3.30 per mmbtu from the quarter ended December 31, 2001. The increase in natural gas pricing was due to the impact of reduced industry drilling activity and the early draws on North American natural gas in storage.

For the year ended December 31, 2002, natural gas prices decreased from the prior year due to high natural gas prices experienced in the first half of 2001. Prices in 2001 were impacted by the increased demand for natural gas due to cold winter temperatures, low inventory levels, increased natural gas-fired power generation and increased export capacity. AECO prices averaged $4.07 per mmbtu for the year 2002 compared to $6.30 per mmbtu for the year 2001.

The Company uses certain financial instruments to protect the downside commodity prices received on the sale of certain oil and natural gas production and its realized prices may be different than market prices. The price realized from the sale of oil was reduced by $1.73 per bbl in the quarter ended December 31, 2002 ($1.62 per bbl reduction and $4.33 per bbl increase, respectively, in the quarters ended September 30, 2002 and December 31, 2001). The price realized from the sale of natural gas was reduced by $0.07 per mcf in the fourth quarter of 2002 ($0.05 per mcf increase and $0.03 per mcf reduction, respectively, in the quarters ended September 30, 2002 and December 31, 2001).

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**	**DEC 31 2002**	**DEC 31 2001**
ROYALTIES					
Oil and liquids *($/bbl)*					
North America	**$ 3.82**	$ 3.92	$ 1.40	**$ 3.42**	$ 2.22
North Sea	**$ 2.79**	$ 2.56	$ 1.52	**$ 2.30**	$ 2.10
Offshore West Africa	**$ 1.35**	$ 1.34	$ 0.64	**$ 1.35**	$ 0.93
Company average	**$ 3.53**	$ 3.56	$ 1.41	**$ 3.16**	$ 2.17
Natural gas *($/mcf)*					
North America	**$ 1.11**	$ 0.69	$ 0.63	**$ 0.80**	$ 1.26
Offshore West Africa	**$ 0.15**	$ 0.15	$ -	**$ 0.15**	$ -
Company average	**$ 1.09**	$ 0.67	$ 0.62	**$ 0.78**	$ 1.25
Company average *($/boe)*	**$ 4.98**	$ 3.80	$ 2.47	**$ 3.91**	$ 4.42
Percentage of revenue *(excluding financial instruments)*					
Oil and liquids	**10.7%**	10.1%	8.3%	**10.1%**	9.3%
Natural gas	**21.4%**	21.8%	20.8%	**20.8%**	22.8%

In North America, fourth quarter 2002 oil and liquids royalties as a percentage of revenue increased from the prior quarter due to certain heavy oil projects reaching payout and becoming subject to higher government royalties. North Sea oil royalties as a percentage of revenue increased from the same three month period in 2001 due to the acquisition of additional interests in the royalty paying Ninian, Murchison and Columba fields. In late November 2002, it was announced that royalties in the North Sea would be eliminated effective January 1, 2003. Offshore West Africa oil royalties increased from the same three month period ended December 31, 2001 due to increased product prices.

North American natural gas royalties on an mcf basis correlate with natural gas product pricing for all comparable periods and remained relatively constant when expressed as a percentage of revenue. Year over year, North American royalties decreased to 21% of revenue for 2002 from 23% for 2001 due to lower average natural gas prices realized in 2002.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001[1]**	**DEC 31 2002**	**DEC 31 2001[1]**
PRODUCTION EXPENSE					
Oil and liquids *($/bbl)*					
North America	**$ 7.34**	$ 6.10	$ 6.60	**$ 6.73**	$ 7.05
North Sea	**$ 14.68**	$ 18.30	$ 10.54	**$ 15.06**	$ 9.00
Offshore West Africa	**$ 13.68**	$ 11.23	$ 19.15	**$ 13.63**	$ 21.77
Company average	**$ 9.10**	$ 8.67	$ 7.52	**$ 8.45**	$ 7.64
Natural gas *($/mcf)*					
North America	**$ 0.55**	$ 0.52	$ 0.52	**$ 0.55**	$ 0.50
North Sea	**$ 1.25**	$ 1.78	$ 1.34	**$ 1.53**	$ 0.94
Offshore West Africa	**$ 1.85**	$ 1.77	$ -	**$ 1.81**	$ -
Company average	**$ 0.57**	$ 0.55	$ 0.53	**$ 0.57**	$ 0.51
Company average *($/boe)*	**$ 6.34**	$ 6.01	$ 5.53	**$ 5.99**	$ 5.69

[1] *Restated for change in accounting policy (see consolidated financial statements note 1).*

The increase in fourth quarter 2002 North America oil and liquids production expense over the comparable three month periods is primarily attributable to the increase in natural gas prices. Natural gas is used to produce the Company's steam to heat the thermal oil formations in the Primrose area of Alberta. North Sea oil production expense decreased in the fourth quarter of 2002 from the prior quarter due to the costs associated with planned maintenance shutdowns of the Ninian North and Ninian Central platforms incurred during the third quarter. Production expense in the North Sea increased year over year as a result of costs incurred to rectify a natural gas pipeline blockage at Kyle experienced in the second quarter of 2002 and the planned maintenance shutdowns of the Ninian fields. Offshore West Africa oil production expense increased from the prior period due to lower production volumes and costs associated with field maintenance conducted in the fourth quarter 2002. Year over year, oil production expense from Offshore West Africa decreased as a result of production ceasing from the higher production expense Kiame field and as a result of higher production levels from the Espoir field.

Natural gas production expense for the year ended December 31, 2002 increased over the prior year due to increased gathering and processing charges and increased toll rates on Ladyfern production in the first half of 2002.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	SEP 30 2002	DEC 31 2001	DEC 31 2002	DEC 31 2001
MIDSTREAM *($ millions)*					
Revenue	**$ 14.8**	$ 13.3	$ 4.9	**$ 52.0**	$ 27.4
Operating costs	**4.5**	3.1	2.9	**14.1**	11.2
Cash flow	**10.3**	10.2	2.0	**37.9**	16.2
Depreciation	**1.9**	1.9	1.2	**7.6**	3.8
Segment earnings before taxes	**$ 8.4**	$ 8.3	$ 0.8	**$ 30.3**	$ 12.4

The Company's midstream assets consist of the 100% owned and operated ECHO pipeline, the 15% interest in the Cold Lake pipeline system, the 62% interest in the operated Pelican Lake pipeline and the 50% interest in the 80 megawatt co-generation system located in the Primrose area. The midstream pipeline assets allow the Company to transport its own production volumes as well as earn third party revenue from excess capacity. The Company transports approximately 85% of its heavy oil through its pipelines to the international mainline liquid pipelines. These midstream assets enhance the Company's ability to control the full range of costs associated with the development and marketing of its heavy oil.

Midstream cash flow and segment earnings before taxes are consistent with the previous quarter ended September 30, 2002. The increase in cash flow and segment earnings before taxes from the comparable periods in 2001 was due to the expansion of the ECHO pipeline, the increased interest in the Pelican Lake pipeline and the commencement of operations from the Cold Lake pipeline system in late December 2001. For the year ended December 31, 2002, the increased pipeline revenues were partially offset by the decline in electricity revenue. Electricity revenue declined from the prior year due to lower prices received for excess electricity sold to the Alberta Power Pool.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	SEP 30 2002	DEC 31 2001	DEC 31 2002	DEC 31 2001
DEPLETION, DEPRECIATION AND AMORTIZATION(1)					
Expense *($ millions)*	**$ 384.2**	$ 401.1	$ 241.2	**$ 1,306.6**	$ 900.0
$/boe	**$ 8.92**	$ 9.08	$ 7.15	**$ 8.51**	$ 6.86

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

Fourth quarter 2002 depletion, depreciation and amortization expense ("DD&A") decreased from the previous quarter in total and per boe due to higher proved reserves at year end. For the three months ended and year ended December 31, 2002, DD&A increased in total and per boe over the comparable periods in 2001 due to 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. Year over year, DD&A was further increased as a result of the Company's decision to exit from its interests in Block 19, Angola, and from the Aje field, Nigeria. The Company charged all related capitalized costs in those countries, totaling $51 million, to DD&A in the second quarter of 2002.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**	**DEC 31 2002**	**DEC 31 2001**
ADMINISTRATION EXPENSE					
Net expense *($ millions)*	**$ 17.7**	$ 17.8	$ 12.0	**$ 61.3**	$ 37.6
$/boe	**$ 0.41**	$ 0.40	$ 0.36	**$ 0.40**	$ 0.29

Administration expense for the three months ended December 31, 2002 remained relatively stable with the prior quarter in total and per boe. For the three months and year ended December 31, 2002, administration expense increased from the comparable periods in 2001 in total and per boe due to higher staffing levels associated with the growth in production and the expanding asset base.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**	**DEC 31 2002**	**DEC 31 2001**
INTEREST EXPENSE					
Interest expense *($ millions)*	**$ 52.7**	$ 48.9	$ 31.4	**$ 158.9**	$ 137.8
$/boe	**$ 1.22**	$ 1.11	$ 0.93	**$ 1.03**	$ 1.05
Average effective interest rate	**5.0%**	4.5%	4.2%	**4.5%**	5.4%

Interest expense for the three months ended December 31, 2002 increased from the third quarter in total and on a boe basis due to a higher average effective interest rate associated with the higher portion of fixed rate debt outstanding. In September 2002, the Company issued US $350 million of US dollar debt securities maturing October 1, 2012, bearing interest at 5.45% and US $350 million of US dollar debt securities maturing June 30, 2033, bearing interest at 6.45%. Interest expense in total and per boe increased over the same three month period in 2001 due to higher average outstanding debt levels and a higher average effective interest rate. Interest expense for the year ended December 31, 2002 increased from the prior year, in total, due to higher average outstanding debt levels as a result of the acquisition of Rio Alto and other property acquisitions. The impact of the higher debt levels was partially offset by the lower overall cost of borrowing. Year over year, interest expense per boe remained consistent due to higher interest expense being offset by increased production.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**	**DEC 31 2002**	**DEC 31 2001**
FOREIGN EXCHANGE *($ millions)*					
Realized foreign exchange loss (gain)	**$ 2.0**	$ (1.9)	$ (3.0)	**$ 3.4**	$ (1.3)
Unrealized foreign exchange (gain) loss	**(0.5)**	42.1	3.4	**(35.1)**	64.1
	$ 1.5	$ 40.2	$ 0.4	**$ (31.7)**	$ 62.8

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to foreign currency translation. The new standard requires foreign exchange gains and losses on the Company's US dollar denominated debt to be expensed immediately rather than deferring and amortizing the gains and losses over the term of the related debt. The change in accounting policy was applied retroactively and foreign exchange losses for the quarter and year ended December 31, 2001 were increased by $2.0 million and $48.1 million, respectively.

Effective July 1, 2002, the Company designated certain US dollar denominated debt as a hedge of its net investment in US dollar based self-sustaining foreign operations. Accordingly, foreign exchange gains of $4.0 million in the fourth quarter 2002 and foreign exchange losses of $41.7 million in the third quarter 2002 are included in the foreign currency translation adjustment in the consolidated balance sheet.

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**	**DEC 31 2002**	**DEC 31 2001**
TAXES					
Taxes other than income tax *($ millions)*					
Current	**$ 15.1**	$ 13.0	$ 10.1	**$ 53.4**	$ 69.3
Deferred	**5.9**	0.6	1.0	**9.5**	(0.2)
Total	**$ 21.0**	$ 13.6	$ 11.1	**$ 62.9**	$ 69.1
Current income tax *($ millions)*					
North Sea	**$ (35.9)**	$ 3.0	$ 10.3	**$ (19.6)**	$ 61.8
Offshore West Africa	**0.7**	3.7	-	**6.0**	-
Large Corporations Tax	**6.8**	5.6	4.7	**21.2**	15.1
Total	**$ (28.4)**	$ 12.3	$ 15.0	**$ 7.6**	$ 76.9
Future income tax *($ millions)*	**$ 178.4**	$ 76.4	$ 1.8	**$ 401.0**	$ 282.5
Effective income tax rate	**41.7%**	41.7%	22.2%	**41.6%**	35.4%

Taxes other than income tax consist of current and deferred petroleum revenue tax ("PRT"), other international taxes and provincial resource surcharges. The fluctuations in taxes other than income tax from comparable periods are due to the impact of changes in oil prices and increased production from PRT paying fields in the North Sea.

North Sea current income tax expense is in a recovery position for the quarter ended December 31, 2002 due to the decision by the UK Government to increase the first year capital allowance rate for plant and machinery expenditures to 100% from the previous rate of 25%. Current income tax expense was also positively impacted by the settlement of certain outstanding matters from prior years in the amount of $11.3 million.

Offshore West Africa current income tax decreased from the previous quarter due to decreased production volumes. Large Corporations Tax increased from the comparable periods due to the higher taxable capital base as a result of increased debt levels and shareholders' equity associated with the acquisition of Rio Alto.

Future income tax expense for the three months ended December 31, 2002 increased over the comparable three month periods due to higher taxable income, as well as the inclusion in the fourth quarter of 2001 of a $17 million reduction in the future income tax liability as a result of a decrease in a Canadian province's corporate income tax rate. Future income taxes also increased for the quarter ended December 31, 2002 over the comparable three month periods because of the increased capital allowance rates noted above, which result in a higher future income tax expense in the North Sea. Future income tax expense for the year ended December 31, 2002 increased over the prior year due to the introduction in the UK of a 10% supplementary charge on profits from North Sea oil and natural gas production. The supplementary charge is in addition to the current corporate tax rate of 30% and excludes any deduction for financing costs. As a result of this additional charge, the future income tax liability in the North Sea was increased by $34 million. The increase in the North Sea future income tax liability was partially offset by a $26 million decrease in the North American future income tax liability as a result of a reduction in a Canadian province's corporate income tax rate in the second quarter of 2002. In 2001, the North American future income tax liability was reduced by $63 million as a result of reductions in Canadian provinces' corporate income tax rates.

CAPITAL EXPENDITURES *($ millions)*	THREE MONTHS ENDED DEC 31 2002	SEP 30 2002	DEC 31 2001[1]	YEAR ENDED DEC 31 2002	DEC 31 2001[1]
Acquisition of Rio Alto[2]	**$ -**	$ 2,393.2	$ -	**$ 2,393.2**	$ -
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 38.5**	$ 333.3	$ 248.4	**$ 440.2**	$ 519.2
Land acquisition and retention	**18.1**	48.4	15.5	**113.5**	100.5
Seismic evaluations	**19.1**	4.9	28.8	**63.4**	94.6
Well drilling, completion and equipping	**138.8**	144.1	106.5	**625.6**	635.3
Pipeline and production facilities	**44.8**	56.5	68.9	**292.2**	395.0
Total net reserve replacement expenditures	**259.3**	587.2	468.1	**1,534.9**	1,744.6
Horizon Project	**19.3**	9.9	11.0	**68.1**	26.8
Midstream	**5.6**	-	45.5	**20.4**	97.3
Abandonments	**4.4**	19.8	3.4	**42.9**	9.4
Head office	**3.2**	3.9	1.7	**9.9**	6.4
Total net capital expenditures	**$ 291.8**	$ 620.8	$ 529.7	**$ 1,676.2**	$ 1,884.5
By segment (excluding Acquisition of Rio Alto)					
North America	**$ 147.7**	$ 331.8	$ 406.8	**$ 1,132.1**	$ 1,485.5
North Sea	**121.3**	230.2	34.3	**333.3**	97.8
Offshore West Africa	**17.2**	58.8	43.1	**190.4**	203.9
Midstream	**5.6**	-	45.5	**20.4**	97.3
Total	**$ 291.8**	$ 620.8	$ 529.7	**$ 1,676.2**	$ 1,884.5

[1] *Certain figures provided for prior periods have been reclassified to conform to the presentation adopted in 2002.*
[2] *September 30, 2002 acquisition costs include adjustment to finalize purchase price allocation.*

Capital expenditures for the year ended December 31, 2002 include the drilling of 162 net natural gas wells, 264 net oil wells and the acquisition of Rio Alto. The Rio Alto acquisition provides the Company with a new core area for natural gas exploration and exploitation activities in western Canada. The Company expects to commence development on this land during the first quarter of 2003.

Fourth quarter 2002 North American capital expenditures saw the continuation of exploration in deeper formations in northeast British Columbia, including the Slave Point trend, where three wells were drilled.

North Sea capital expenditures for the three months ended December 31, 2002 includes the drilling of an additional well in the Columba B field and a third producing well at the Banff field. During the year, North Sea capital expenditures included the consolidation of interests in the Banff, Kyle, Ninian, Lyell, Murchison and Columba fields. The Company also acquired an interest in 12 licenses covering 20 exploration blocks and part blocks, and additional equity interests in the Brent and Ninian pipelines and the Sullom Voe Terminal. The consideration for the acquisitions includes cash payments and the Company's interests in the Harding, Pierce and Claymore fields. As a result of these acquisitions, the Company was able to assume operatorship of several fields during 2002. During 2003, the Company plans to drill 18 wells in the North Sea, primarily in the northern portion.

Fourth quarter 2002 Offshore West Africa capital expenditures in Côte d'Ivoire include continued development on the Baobab field. The fourth quarter 2002 also included the continued development of the operated Espoir field. Unanticipated uphole faults delayed completion of the fourth producing well. During December 2002, a satellite pool, Emien, was drilled but encountered no hydrocarbons. The Company anticipates drilling a second, larger satellite pool, Acajou, during the first half of 2003. The Company's development activities in Côte d'Ivoire remain unaffected by recent political insurrection in the country due to operations being located offshore. The Company has established back up facilities in a neighbouring country to ensure operations are not affected should conditions significantly deteriorate. During the year, the Company also entered into a production sharing agreement ("PSA") for Block 16, offshore Angola. The Company will retain a 50% working interest. The PSA was effective September 1, 2002 for an initial four-year period.

	DEC 31 2002	SEP 30 2002	DEC 31 2001[1]
LIQUIDITY AND CAPITAL RESOURCES *($ millions, except ratios)*			
Working capital deficit	**$ 13.8**	$ 364.4	$ 5.6
Long-term debt	**4,074.0**	4,169.6	2,669.2
Total	**$ 4,087.8**	$ 4,534.0	$ 2,674.8
Shareholders' equity			
Preferred securities	**$ 126.4**	$ 126.9	$ 127.4
Share capital	**2,303.8**	2,289.0	1,698.3
Retained earnings	**2,414.3**	2,222.7	1,908.5
Foreign currency translation adjustment	**23.6**	22.7	72.8
Total	**$ 4,868.1**	$ 4,661.3	$ 3,807.0
Debt to cash flow[2]	**1.8x**	2.3x	1.4x
Debt to book capitalization	**45.6%**	47.2%	41.2%
Debt to market capitalization	**38.9%**	37.9%	34.9%
After tax return on average common shareholders' equity[2]	**13.8%**	10.6%	18.7%
After tax return on average capital employed[2]	**8.9%**	7.3%	12.2%

(1) *Restated for change in accounting policy (see consolidated financial statements note 2).*

(2) *Based on trailing 12-month period and does not include amounts related to acquired assets for the six-month period prior to June 30, 2002.*

The ratios above have been calculated with the outstanding preferred securities of the Company classified as equity. If the preferred securities were classified as long-term debt, debt to cash flow for the trailing 12-month period ended December 31, 2002, would be 1.9x (September 30, 2002 – 2.4x, December 31, 2001 – 1.5x). Debt to book capitalization would be 47.0% at December 31, 2002 (September 30, 2002 – 48.7%, December 31, 2001 – 43.2%) had the preferred securities been classified as long-term debt, while debt to market capitalization would be 40.2%, 39.0% and 36.6%, respectively.

SENSITIVITY ANALYSIS (1)

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

	Cash flow from operations(2) *($ millions)*	**Cash flow from operations**(2) *(per share) (basic)*	**Net earnings**(2) *($ millions)*	**Net earnings**(2) *(per share) (basic)*
Price changes				
Oil – WTI US $1.00/bbl(3)				
Excluding financial derivatives	$104	$0.78	$69	$0.52
Including financial derivatives	$69-$73	$0.51-$0.55	$45-$48	$0.34-$0.36
Natural gas – AECO Cdn $0.10/mcf(3)				
Excluding financial derivatives	$38	$0.28	$23	$0.17
Including financial derivatives	$38	$0.28	$23	$0.17
Volume changes				
Oil – 10,000 bbls/d	$54	$0.41	$23	$0.17
Natural gas – 10 mmcf/d	$12	$0.09	$4	$0.03
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $(3)				
Excluding financial derivatives	$66	$0.49	$40	$0.30
Including financial derivatives	$61-$63	$0.45-$0.47	$37-$39	$0.28-$0.29
Interest rate change – 1%	$24	$0.18	$15	$0.11

(1) *The sensitivities are calculated based on 2002 fourth quarter results.*
(2) *Attributable to common shareholders.*
(3) *For details of financial instruments in place, see consolidated financial statements note 8.*

OTHER OPERATING HIGHLIGHTS

	THREE MONTHS ENDED			YEAR ENDED	
	DEC 31 2002	**SEP 30 2002**	**DEC 31 2001**(1)	**DEC 31 2002**	**DEC 31 2001**(1)
NETBACK ANALYSIS *($/boe, except daily production)*					
Daily production *(boe/d)*	**468,132**	479,949	366,594	**420,722**	359,347
Sales price	**$ 30.54**	$ 26.26	$ 19.62	**$ 26.25**	$ 27.15
Royalties	**4.98**	3.80	2.47	**3.91**	4.42
Production expense	**6.34**	6.01	5.53	**5.99**	5.69
Netback	**19.22**	16.45	11.62	**16.35**	17.04
Midstream contribution	**(0.24)**	(0.23)	(0.06)	**(0.25)**	(0.12)
Administration	**0.41**	0.40	0.36	**0.40**	0.29
Interest	**1.22**	1.11	0.93	**1.03**	1.05
Realized foreign exchange loss (gain)	**0.05**	(0.04)	(0.09)	**0.02**	(0.01)
Taxes other than income tax (current)	**0.35**	0.29	0.30	**0.35**	0.53
Current income tax (North Sea)	**(0.83)**	0.07	0.31	**(0.13)**	0.47
Current income tax (Offshore West Africa)	**0.01**	0.08	-	**0.04**	-
Current income tax (Large Corporations Tax)	**0.16**	0.13	0.14	**0.14**	0.11
Cash flow	**$ 18.09**	$ 14.64	$ 9.73	**$ 14.75**	$ 14.72

(1) *Restated for change in accounting policy (see consolidated financial statements notes 1 and 2).*

	YEAR ENDED DECEMBER 31, 2002			
	North America	**North Sea**	**Offshore West Africa**	**Total**
SEGMENTED NETBACK				
Oil and liquids *($/bbl, except daily production)*				
Daily production *(bbls/d)*	**169,675**	**38,876**	**6,784**	**215,335**
Sales price	**$ 27.04**	**$ 39.79**	**$ 40.10**	**$ 29.76**
Royalties	**3.42**	**2.30**	**1.35**	**3.16**
Production expense	**6.73**	**15.06**	**13.63**	**8.45**
Netback(1)	**$ 16.89**	**$ 22.43**	**$ 25.12**	**$ 18.15**
Natural gas *($/mcf, except daily production)*				
Daily production *(mmcf/d)*	**1,204**	**27**	**1**	**1,232**
Sales price	**$ 3.78**	**$ 2.75**	**$ 4.82**	**$ 3.76**
Royalties	**0.80**	**-**	**0.15**	**0.78**
Production expense	**0.55**	**1.53**	**1.81**	**0.57**
Netback(1)	**$ 2.43**	**$ 1.22**	**$ 2.86**	**$ 2.41**
Barrels of oil equivalent *($/boe, except daily production)*				
Daily production *(boe/d)*	**370,337**	**43,391**	**6,994**	**420,722**
Sales price	**$ 24.69**	**$ 37.40**	**$ 39.76**	**$ 26.25**
Royalties	**4.17**	**2.06**	**1.34**	**3.91**
Production expense	**4.86**	**14.45**	**13.54**	**5.99**
Netback(1)	**$ 15.66**	**$ 20.89**	**$ 24.88**	**$ 16.35**

(1) *Netbacks do not include midstream operations.*

CONSOLIDATED BALANCE SHEETS *(millions of Canadian dollars) (unaudited)*

	DECEMBER 31 2002	DECEMBER 31 2001
ASSETS		
Current assets		
Cash	**$ 30.0**	$ 15.0
Accounts receivable and other	**745.2**	509.0
	775.2	524.0
Property, plant and equipment *(net)*	**12,499.6**	8,442.9
Deferred charges *(note 4)*	**84.1**	-
	$ 13,358.9	$ 8,966.9
LIABILITIES		
Current liabilities		
Accounts payable	**$ 336.5**	$ 249.5
Accrued liabilities	**428.4**	264.2
Current portion of long-term debt *(note 5)*	**24.1**	15.9
	789.0	529.6
Long-term debt *(note 5)*	**4,074.0**	2,669.2
Future site restoration	**440.4**	193.8
Future income tax	**3,187.4**	1,767.3
	8,490.8	5,159.9
SHAREHOLDERS' EQUITY		
Preferred securities *(note 2)*	**126.4**	127.4
Share capital *(note 6)*	**2,303.8**	1,698.3
Retained earnings	**2,414.3**	1,908.5
Foreign currency translation adjustment	**23.6**	72.8
	4,868.1	3,807.0
	$ 13,358.9	$ 8,966.9

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**
CONSOLIDATED STATEMENTS OF EARNINGS *(millions of Canadian dollars, except per share amounts) (unaudited)*				
Revenue	**$ 1,330.3**	$ 666.4	**$ 4,083.2**	$ 3,588.8
Less: royalties	**(214.3)**	(83.2)	**(600.3)**	(580.3)
	1,116.0	583.2	**3,482.9**	3,008.5
Expenses				
Production	**277.7**	189.4	**933.9**	757.9
Depletion, depreciation and amortization	**386.1**	242.4	**1,314.2**	903.8
Administration	**17.7**	12.0	**61.3**	37.6
Interest	**52.7**	31.4	**158.9**	137.8
Foreign exchange loss (gain) *(note 2)*	**1.5**	0.4	**(31.7)**	62.8
Loss on sale of United States assets	**-**	24.1	**-**	24.1
	735.7	499.7	**2,436.6**	1,924.0
Earnings Before Taxes	**380.3**	83.5	**1,046.3**	1,084.5
Taxes other than income tax	**21.0**	11.1	**62.9**	69.1
Current income tax	**(28.4)**	15.0	**7.6**	76.9
Future income tax	**178.4**	1.8	**401.0**	282.5
Net Earnings	**209.3**	55.6	**574.8**	656.0
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.6)	**(6.0)**	(5.9)
Revaluation of preferred securities *(note 2)*	**0.5**	(1.1)	**1.0**	(7.5)
Net Earnings Attributable to Common Shareholders	**$ 208.3**	$ 52.9	**$ 569.8**	$ 642.6
Net Earnings per Common Share Attributable to Common Shareholders *(note 7)*				
Basic	**$ 1.56**	$ 0.44	**$ 4.46**	$ 5.30
Diluted	**$ 1.51**	$ 0.43	**$ 4.31**	$ 5.17

	YEAR ENDED DECEMBER 31	
	2002	**2001**
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS *(millions of Canadian dollars) (unaudited)*		
Balance – Beginning of Period as Previously Reported	**$ 1,979.5**	$ 1,406.0
Change in accounting policy – foreign exchange *(note 2)*	**(71.0)**	(15.4)
Balance – Beginning of Period as Restated	**1,908.5**	1,390.6
Net earnings	**574.8**	656.0
Dividend on common shares *(note 6)*	**(64.0)**	(48.5)
Dividend on preferred securities *(net of tax)*	**(6.0)**	(5.9)
Revaluation of preferred securities *(note 2)*	**1.0**	(7.5)
Purchase of common shares *(note 6)*	**-**	(76.2)
Balance – End of Period	**$ 2,414.3**	$ 1,908.5

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**

CONSOLIDATED STATEMENTS OF CASH FLOWS *(millions of Canadian dollars) (unaudited)*

	THREE MONTHS ENDED DECEMBER 31 2002	THREE MONTHS ENDED DECEMBER 31 2001	YEAR ENDED DECEMBER 31 2002	YEAR ENDED DECEMBER 31 2001
Operating Activities				
Net earnings	**$ 209.3**	$ 55.6	**$ 574.8**	$ 656.0
Non-cash items				
Depletion, depreciation and amortization	**386.1**	242.4	**1,314.2**	903.8
Unrealized foreign exchange (gain) loss	**(0.5)**	3.4	**(35.1)**	64.1
Deferred petroleum revenue tax	**5.9**	1.0	**9.5**	(0.2)
Future income tax	**178.4**	1.8	**401.0**	282.5
Loss on sale of United States assets	**-**	24.1	**-**	24.1
Cash flow provided from operations	**779.2**	328.3	**2,264.4**	1,930.3
Deferred charges	**(25.8)**	-	**(84.1)**	-
Net change in non-cash working capital	**(99.9)**	(32.6)	**(156.9)**	(42.2)
	653.5	295.7	**2,023.4**	1,888.1
Financing Activities				
(Repayment of) increase in bank credit facilities	**(85.1)**	350.6	**(1,234.3)**	(442.3)
Issue of US dollar debt securities	**-**	-	**1,749.3**	615.2
Repayment of senior unsecured notes	**-**	(15.8)	**(15.9)**	(15.8)
Repayment of capital lease obligations	**(2.0)**	-	**(3.9)**	-
Repayment of limited recourse loan	**-**	-	**-**	(11.8)
Issue of capital stock	**14.8**	4.5	**84.1**	42.8
Purchase of common shares	**-**	-	**-**	(113.3)
Dividend on common shares	**(16.6)**	(12.1)	**(59.4)**	(36.4)
Dividend on preferred securities	**(2.6)**	(2.6)	**(10.4)**	(10.3)
Net change in non-cash working capital	**43.6**	(0.1)	**26.0**	7.4
	(47.9)	324.5	**535.5**	35.5
Investing Activities				
Business combination, net of cash acquired *(note 3)*	**-**	-	**(843.2)**	-
Expenditures on property, plant and equipment	**(294.9)**	(578.3)	**(1,752.3)**	(1,947.5)
Net proceeds on sale of property, plant and equipment	**3.1**	48.6	**76.1**	63.0
Net expenditures on property, plant and equipment	**(291.8)**	(529.7)	**(2,519.4)**	(1,884.5)
Net change in non-cash working capital	**(299.0)**	(110.5)	**(24.5)**	(52.1)
	(590.8)	(640.2)	**(2,543.9)**	(1,936.6)
Increase (decrease) in Cash	**14.8**	(20.0)	**15.0**	(13.0)
Cash – Beginning of Period	**15.2**	35.0	**15.0**	28.0
Cash – End of Period	**$ 30.0**	$ 15.0	**$ 30.0**	$ 15.0

For supplementary information, see note 9.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS *(tabular amounts in millions of Canadian dollars)*

1. ACCOUNTING POLICIES

The 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 and methods of computation as the audited consolidated financial statements of the Company as at December 31, 2001, except as described below in note 1 and in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual 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, 2001.

Hedge of net investment in self-sustaining foreign operations

Effective July 1, 2002, the Company 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.

Midstream operations

As a result of the Company's increasing midstream activities, the Company determined that effective January 1, 2002, the midstream activities within North America constitute a distinct operating segment. The Company carries its midstream assets at the lower of net capitalized cost and net recoverable amount. Midstream assets are depreciated over their estimated useful lives of 20 to 30 years.

Comparative figures

Certain figures provided for prior periods have been reclassified to conform to the presentation adopted in 2002.

2. CHANGE IN ACCOUNTING POLICY

Foreign currency translation

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to foreign currency translation. As a result of adopting this new standard, gains or losses on the translation of long-term debt denominated in US dollars are no longer deferred and amortized over the term of the debt, but are recognized in net earnings immediately. This new standard has been adopted retroactively and prior periods have been restated.

The new standard affects the Company's accounting for US dollar denominated long-term debt and preferred securities. Adoption of the new accounting policy had the following effects on the Company's consolidated financial statements:

	THREE MONTHS ENDED		YEAR ENDED	
	DEC 31 2002	**DEC 31 2001**	**DEC 31 2002**	**DEC 31 2001**
Increase (decrease) deferred foreign exchange loss	**$ -**	$ 2.0	**$ -**	$ (61.9)
(Decrease) increase preferred securities	**$ (0.5)**	$ 1.0	**$ (1.0)**	$ 9.1
Decrease opening retained earnings	**$ (21.7)**	$ -	**$ (71.0)**	$ (15.4)
Foreign exchange (gain) loss	**$ (4.0)**	$ 2.0	**$ (53.3)**	$ 48.1
Revaluation of preferred securities	**$ (0.5)**	$ 1.0	**$ (1.0)**	$ 7.5
Increase (decrease) net earnings per common share				
- Basic	**$ 0.03**	$ (0.03)	**$ 0.42**	$ (0.46)
- Diluted	**$ 0.03**	$ (0.02)	**$ 0.40**	$ (0.38)

3. BUSINESS COMBINATION

Rio Alto Exploration Ltd.

The Company paid cash of $850.0 million and issued 10,008,218 common shares with an attributed value of $522.4 million to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement (the "Plan of Arrangement"). Rio Alto was engaged in the exploration for and production of oil and natural gas in western Canada and South America. Under the Plan of Arrangement, subsidiaries of Rio Alto that held its South American properties were sold to a new company, Rio Alto Resources International Inc. ("Rio Alto International"), and each shareholder of Rio Alto received one share of Rio Alto International for each Rio Alto common share held.

The acquisition was accounted for based on the purchase method. Results of Rio Alto are consolidated with the results of the Company effective July 1, 2002. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

	JULY 1 2002
Purchase price:	
Cash consideration	$ 850.0
Share consideration	522.4
Cash acquired	(6.8)
Non-cash working capital assumed	91.3
Long-term debt assumed	936.3
Total purchase price	$ 2,393.2
Purchase price allocated as follows:	
Property, plant and equipment	$ 3,411.8
Future site restoration	(43.5)
Future income tax	(975.1)
	$ 2,393.2

4. DEFERRED CHARGES

Deferred charges include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. The deferred charges are amortized over the original term of the related instrument.

5. LONG-TERM DEBT

	DECEMBER 31 2002	DECEMBER 31 2001
Bank credit facilities		
Canadian dollar debt	**$ 728.0**	$ 1,003.4
US dollar debt *(2002 – US $150 million, 2001 – US $296 million)*	**236.9**	471.4
Medium-term notes	**250.0**	250.0
Senior unsecured notes *(2002 – US $318 million, 2001 – US $203 million)*	**498.6**	323.3
US dollar debt securities *(2002 – US $1,500 million, 2001 – US $400 million)*	**2,369.4**	637.0
Obligations under capital leases	**15.2**	-
	4,098.1	2,685.1
Current portion of long-term debt	**(24.1)**	(15.9)
	$ 4,074.0	$ 2,669.2

Bank credit facilities

At December 31, 2002, the Company had unsecured bank credit facilities of $2,275 million comprised of a $100 million operating demand facility, a revolving credit and term loan facility of $1,675 million, and a $500 million acquisition term credit facility repayable July 3, 2004. In the fourth quarter 2002, the Company repaid and cancelled a $725 million credit and term loan facility and a US $150 million credit and term loan facility.

Debt under the bank credit facilities totaling $100 million is subject to an interest rate swap that fixes the rate at 5.08% plus a stamping fee (note 8).

In addition to the outstanding debt, letters of credit aggregating $25.1 million have been issued.

Senior unsecured notes

On July 1, 2002, as part of the Rio Alto acquisition, the Company assumed US $125 million of senior unsecured notes maturing December 19, 2005, bearing interest at 7.69%. Through a currency swap, the interest and principal repayment amounts are fixed at 7.30% and $193.7 million, respectively (note 8).

US dollar debt securities

On January 23, 2002, the Company issued US $400 million of US dollar debt securities maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 8).

On September 16, 2002, the Company issued US $350 million of US dollar debt securities maturing October 1, 2012, bearing interest at 5.45% and US $350 million of US dollar debt securities maturing June 30, 2033, bearing interest at 6.45%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the amount (note 8). The Company has US $300 million remaining on a US $1 billion shelf prospectus filed on August 16, 2002 that allows for the issue of debt securities until September 2004. If issued, these securities will bear interest as determined at the date of issuance.

Obligations under capital leases

The obligations under capital leases bear interest at an average effective interest rate of 6.91% and are secured by the related assets.

6. SHARE CAPITAL

Issued

	DECEMBER 31, 2002	
	Number of shares *(thousands)*	**Amount**
Common shares		
Balance – January 1, 2002	**121,201**	**$ 1,698.3**
Issued upon acquisition of Rio Alto	**10,008**	**522.4**
Issued upon exercise of stock options	**2,523**	**82.1**
Issue of flow-through shares *(net of tax)*	**60**	**1.3**
Cancellation of shares	**(16)**	**(0.3)**
Balance – December 31, 2002	**133,776**	**$ 2,303.8**

The Company issued 10,008,218 common shares at an attributed value of $522.4 million as part of the consideration to acquire Rio Alto (note 3).

In January 2002, the Company issued 60,000 flow-through common shares to a director of the Company at a price of $39.00 per common share, for total proceeds of $2.3 million. The value of the common shares was determined as the closing market price of the common shares on The Toronto Stock Exchange on the day prior to the allotment.

During the year, 16,288 common shares were returned to treasury and cancelled on the expiry of the conversion period for exchanging shares of companies previously acquired for common shares of the Company.

Normal Course Issuer Bid

In January 2001, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of The Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,114,726 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 22, 2001 and ending January 21, 2002. As at January 21, 2002, the Company had purchased 2,537,800 common shares for a total cost of $113.3 million. The excess cost over book value of the common shares purchased was applied to contributed surplus and retained earnings.

In January 2002, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,060,180 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 23, 2002 and ending January 22, 2003. No common shares were purchased under this renewed Normal Course Issuer Bid.

In January 2003, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,692,799 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As of the date hereof, 175,600 common shares have been purchased under this renewed Normal Course Issuer Bid.

Dividend policy

In January 2001, the Company announced a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year.

In February 2002, the Board of Directors increased the Company's regular quarterly dividend to $0.125 per common share commencing with the April 1, 2002 payment.

In February 2003, the Board of Directors increased the Company's regular quarterly dividend to $0.15 per common share commencing with the April 1, 2003 payment.

Stock options

	DECEMBER 31, 2002	
	Stock options *(thousands)*	**Weighted average exercise price**
Outstanding – January 1, 2002	**12,051**	**$ 34.77**
Granted	**3,845**	**$ 41.88**
Exercised	**(2,523)**	**$ 32.54**
Forfeited	**(491)**	**$ 40.03**
Outstanding – December 31, 2002	**12,882**	**$ 37.13**
Exercisable – December 31, 2002	**3,508**	**$ 32.53**

Stock-based compensation costs

The Company accounts for its stock-based compensation using the intrinsic value method, whereby no compensation costs have been recorded for stock options granted.

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**
Stock-based compensation costs	**$ 6.8**	$ 5.1	**$ 24.9**	$ 18.8
Net earnings attributable to common shareholders				
As reported	**$ 208.3**	$ 52.9	**$ 569.8**	$ 642.6
Pro forma	**$ 201.5**	$ 47.8	**$ 544.9**	$ 623.8
Net earnings per common share attributable to common shareholders				
Basic				
As reported	**$ 1.56**	$ 0.44	**$ 4.46**	$ 5.30
Pro forma	**$ 1.51**	$ 0.40	**$ 4.26**	$ 5.14
Diluted				
As reported	**$ 1.51**	$ 0.43	**$ 4.31**	$ 5.17
Pro forma	**$ 1.46**	$ 0.39	**$ 4.12**	$ 5.03

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

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**
Fair value of options granted *(per common share)*				
Directors, officers and executives	**$ -**	$ -	**$ 14.70**	$ 16.52
Other employees	**$ 10.19**	$ 11.65	**$ 12.29**	$ 13.56
Risk-free interest rate	**3.8%**	4.5%	**3.7%**	5.2%
Expected life *(years)*				
Directors, officers and executives	**-**	-	**5.5**	5.5
Other employees	**4.0**	3.6	**3.7**	3.6
Expected volatility	**27%**	34%	**35%**	39%
Expected dividend yield	**1.2%**	1.0%	**1.2%**	1.0%

7. NET EARNINGS AND CASH FLOW FROM OPERATIONS PER COMMON SHARE

The following table provides a reconciliation between basic and diluted per common share amounts:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**
Weighted average common shares outstanding *(thousands)*				
Basic	**133,618**	121,157	**127,883**	121,300
Effect of dilutive stock options	**2,036**	1,729	**2,744**	2,594
Assumed settlement of preferred securities with common shares[1]	**2,901**	-	**2,681**	2,883
Diluted	**138,555**	122,886	**133,308**	126,777
Net earnings attributable to common shareholders	**$ 208.3**	$ 52.9	**$ 569.8**	$ 642.6
Dividend on preferred securities *(net of tax)*[1]	**1.5**	-	**6.0**	5.9
Revaluation of preferred securities[1]	**(0.5)**	-	**(1.0)**	7.5
Diluted net earnings attributable to common shareholders	**$ 209.3**	$ 52.9	**$ 574.8**	$ 656.0
Net earnings per common share attributable to common shareholders				
Basic	**$ 1.56**	$ 0.44	**$ 4.46**	$ 5.30
Diluted	**$ 1.51**	$ 0.43	**$ 4.31**	$ 5.17

[1] *Preferred securities are anti-dilutive for the three months ended December 31, 2001, but are dilutive for the three months ended December 31, 2002 and years ended December 31, 2002 and December 31, 2001.*

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**
Cash flow from operations attributable to common shareholders	**$ 776.6**	$ 325.7	**$ 2,254.0**	$ 1,920.0
Dividend on preferred securities[1]	**2.6**	-	**10.4**	10.3
Diluted cash flow from operations attributable to common shareholders	**$ 779.2**	$ 325.7	**$ 2,264.4**	$ 1,930.3
Cash flow from operations per common share attributable to common shareholders				
Basic	**$ 5.81**	$ 2.69	**$ 17.63**	$ 15.83
Diluted	**$ 5.62**	$ 2.65	**$ 16.99**	$ 15.23

[1] *Preferred securities are anti-dilutive for the three months ended December 31, 2001, but are dilutive for the three months ended December 31, 2002 and years ended December 31, 2002 and December 31, 2001.*

8. FINANCIAL INSTRUMENTS

The Company uses certain derivative financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The following summarizes transactions outstanding as at February 26, 2003, which includes all transactions outstanding at December 31, 2002:

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps	Jan. 2003 – Dec. 2003	15,000 bbls/d	US $1.00	Dated Brent/WTI
Oil price collars	Jan. 2003 – Mar. 2003	117,333 bbls/d	US $22.74 – US $28.26	WTI
	Apr. 2003 – Jun. 2003	110,667 bbls/d	US $22.48 – US $28.06	WTI
	Jul. 2003 – Sep. 2003	73,333 bbls/d	US $23.45 – US $28.75	WTI
	Oct. 2003 – Dec. 2003	40,000 bbls/d	US $24.00 – US $30.17	WTI

	Remaining Term	Volume	Average Price	Index
Natural Gas				
NYMEX collar	Jan. 2003 – Oct. 2003	30,000 mmbtu/d	US $2.88 – US $6.12	NYMEX
Sumas fixed	Jan. 2003 – Oct. 2003	10,000 mmbtu/d	Cdn $2.85	Sumas
AECO collars	Jan. 2003 – Mar. 2003	500,000 GJ/d	Cdn $4.16 – Cdn $6.98	AECO
	Apr. 2003 – Jun. 2003	240,000 GJ/d	Cdn $4.13 – Cdn $6.11	AECO
	Jul. 2003 – Sep. 2003	40,000 GJ/d	Cdn $3.50 – Cdn $5.38	AECO
	Oct. 2003	40,000 GJ/d	Cdn $3.50 – Cdn $5.38	AECO

	Remaining Term	Amount *($ millions)*	Average Exchange Rate *(US $/Cdn $)*
Foreign Currency			
Currency collars	Jan. 2003 – May 2003	US $4.2/month	1.43 – 1.53
	Jan. 2003 – Aug. 2004	US $25.0/month	1.51 – 1.59

	Remaining Term	Amount *($ millions)*	Exchange Rate *(US $/Cdn $)*	Interest Rate *(US $)*	Interest Rate *(Cdn $)*
Currency Swap	Jan. 2003 – Dec. 2005	US $125.0	1.55	7.69%	7.30%

	Remaining Term	Amount *($ millions)*	Fixed Rate	Floating Rate
Interest Rate				
Swaps – fixed to floating	Jan. 2003 – Jul. 2004	US $200.0	6.70%	LIBOR + 2.09%
	Jan. 2003 – Jul. 2006	US $200.0	6.70%	LIBOR + 1.58%
	Jan. 2003 – Jan. 2005	US $200.0	7.20%	LIBOR + 3.00%
	Jan. 2003 – Jan. 2007	US $200.0	7.20%	LIBOR + 2.23%
	Jan. 2003 – Oct. 2012	US $200.0	5.45%	LIBOR + 0.81%
Swaps – floating to fixed	Jan. 2003 – Mar. 2004	Cdn $100.0	5.08%	CDOR
	Jan. 2003 – Mar. 2007	Cdn $16.5	7.36%	CDOR

9. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**
Interest paid	**$ 28.4**	$ 28.4	**$ 132.2**	$ 127.4
Taxes paid	**$ 67.9**	$ 42.7	**$ 160.4**	$ 161.2

10. SEGMENTED INFORMATION

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2002	**2001**	**2002**	**2001**
Revenue				
North America	**$ 1,077.6**	$ 540.5	**$ 3,337.3**	$ 2,996.8
North Sea	**207.7**	115.2	**592.4**	523.0
Offshore West Africa	**30.2**	5.8	**101.5**	41.6
Midstream	**14.8**	4.9	**52.0**	27.4
	$ 1,330.3	$ 666.4	**$ 4,083.2**	$ 3,588.8
Net Earnings (Loss)				
North America	**$ 176.9**	$ 33.9	**$ 564.7**	$ 537.4
North Sea	**19.0**	25.7	**(1.1)**	120.6
Offshore West Africa	**8.5**	(4.5)	**(6.3)**	(9.1)
Midstream	**4.9**	0.5	**17.5**	7.1
	209.3	55.6	**574.8**	656.0
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.6)	**(6.0)**	(5.9)
Revaluation of preferred securities	**0.5**	(1.1)	**1.0**	(7.5)
Net Earnings Attributable to Common Shareholders	**$ 208.3**	$ 52.9	**$ 569.8**	$ 642.6
Additions to Property, Plant and Equipment *(excluding Acquisition of Rio Alto)*				
North America	**$ 128.4**	$ 500.1	**$ 1,064.0**	$ 1,649.1
North Sea	**314.9**	34.3	**566.3**	97.8
Offshore West Africa	**17.3**	43.1	**190.4**	203.9
Horizon Project	**19.3**	11.0	**68.1**	26.8
Midstream	**5.6**	45.5	**20.4**	97.3
	$ 485.5	$ 634.0	**$ 1,909.2**	$ 2,074.9

	PROPERTY, PLANT AND EQUIPMENT		TOTAL ASSETS	
	DECEMBER 31 2002	**DECEMBER 31 2001**	**DECEMBER 31 2002**	**DECEMBER 31 2001**
Segmented Assets				
North America	**$ 10,278.5**	$ 6,823.4	**$ 10,943.3**	$ 7,231.9
North Sea	**1,278.5**	866.2	**1,428.1**	941.6
Offshore West Africa	**518.3**	409.9	**549.4**	433.2
Horizon Project	**228.7**	160.6	**228.7**	160.6
Midstream	**195.6**	182.8	**209.4**	199.6
	$ 12,499.6	$ 8,442.9	**$ 13,358.9**	$ 8,966.9

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated July 24, 2001. These ratios are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the year ended December 31, 2002:	
Interest coverage *(times)*	
Net earnings	7.2[(1)]
Cash flow from operations attributable to common shareholders	15.3[(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 year ended December 31, 2002, would be 6.8x and the cash flow coverage ratio for the year ended December 31, 2002 would be 14.4x.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time, on Wednesday, February 26, 2003. The North American conference call number is 1-888-799-1759 and the outside North America conference call number is 1-416-620-2412. 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 March 5, 2003, inclusive. To access postview in North America, dial 1-800-558-5253 and enter the passcode 21111914. Those outside of North America dial 1-416-626-4100 and enter the passcode number 21111914.

2003 FIRST QUARTER RESULTS

2003 first quarter results are scheduled for release Wednesday, May 7, 2003. A conference call will be held that day at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

ANNUAL GENERAL MEETING

Canadian Natural Resources Limited's Annual General Meeting will be held on Thursday, May 8, 2003 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, 333 – 4 Avenue SW, Calgary, Alberta. All shareholders are invited to attend.

For further information, please contact:

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

Telephone: (403) 514-7777
Facsimile: (403) 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
Executive Vice-President
Operations

COREY B. BIEBER
Director
Investor Relations