CANADIAN NATURAL RESOURCES LIMITED

Q3
Nine months ended
September 30, 2002

CANADIAN NATURAL ANNOUNCES RECORD QUARTERLY CASH FLOW

In commenting on third quarter 2002 results, Canadian Natural's Chairman, Allan Markin, stated "Canadian Natural Resources has continued to undertake steps that strengthened the Company's position as a major international independent. The acquisition of Rio Alto Exploration Ltd. added significant production and upside potential on the natural gas front. We will take a methodical approach to developing the Northwest Alberta properties and have already identified opportunities for economically unlocking the Cardium natural gas potential. Over the next few years this acquisition will add significantly to the portfolio of natural gas exploration and development opportunities available to the Company."

"Also during the quarter, a major acquisition of properties in the northern portion of the North Sea solidified our presence there. We now control and have majority ownership interests in these assets, similar to our holdings throughout the rest of the world. Our focus has always been exploitation and this acquisition will enable the Company to carry out this business plan in the North Sea."

"During the quarter, production from the Ladyfern field started its steep decline. We always expected 70% production declines, but were unsure of when they would commence. We knew that this decline would have to be replaced and so given weaker natural gas pricing, determined it prudent to defer other natural gas drilling to 2003. Consequently, our natural gas drilling is only one-third of what it was last year. In 2003, our natural gas drilling activity will exceed 2001 levels to stem further expected declines from Ladyfern and keep 2003 natural gas production constant from entry to exit."

"Our 2003 budget points out two recurring themes that will continue for the next several years. First, growth on total base production will continue at rates approximating 10% per annum. Second, an increasing amount of capital spent today is related to projects that do not add production or cash flow until future years. As an example, in 2003, expenditures relating to the drilling of high pressure wells at Primrose, development costs relating to the Baobab field and the Horizon Oil Sands Project will not yield cash returns until future years. The 2003 budget provides manageable, efficient 10% production growth and a strong base for sustainable growth in the future."

"I would like to thank all of the employees that were instrumental in accomplishing a seamless integration of newly acquired properties into Canadian Natural. By working together we have been able to minimize disruptions and ensure delivery of value to our shareholders."

HIGHLIGHTS OF THE THIRD QUARTER

- Natural gas sales volumes of 1,427 million cubic feet per day, an increase of 54% from the third quarter of last year and a 32% increase from the previous quarter of this year.

- Oil and liquids sales volumes of 242 thousand barrels per day. Production of primary heavy oil and thermal heavy oil accounted for 22% of production on a barrel of oil equivalent basis, down from 24% during the previous quarter.

- Record quarterly cash flow of $644 million ($4.83 per common share) compared with $437 million ($3.62 per common share) in the third quarter of 2001 and $475 million ($3.86 per common share) in the previous quarter.

- Net earnings of $117 million ($0.88 per common share) compared with $81 million ($0.67 per common share) for the third quarter of 2001 and $145 million ($1.18 per common share) in the previous quarter. Adjusted net earnings amounted to $164 million ($1.23 per common share) compared with $143 million ($1.18 per common share) for the third quarter of 2001 and $118 million ($0.96 per common share) in the previous quarter.

- Realized an 18% increase in the wellhead price for its oil and liquids sales over the corresponding quarter of 2001, as a result of lower price differentials for heavy oil production.

- Successfully completed the $2.3 billion acquisition of Rio Alto Exploration Ltd. ("Rio Alto") with closing effective July 1, 2002. This acquisition added significant natural gas production resulting in Canadian Natural becoming one of North America's largest natural gas producers.

- Successfully negotiated the acquisition of ownership interests and transition to operator of two producing platforms in the North Sea resulting in Canadian Natural now owning an average interest of 75% and operating 90% of its producing properties in the North Sea.

- Continued the Design Basis Memorandum for the proposed Horizon Oil Sands Project, located 80 kilometers north of Fort McMurray in Northeastern Alberta, which is expected to produce approximately 230 thousand barrels per day of light synthetic crude oil.

- Brought one additional producing well on-stream at the Espoir field offshore Côte d'Ivoire during the quarter. Additional producing wells scheduled for completion during the third quarter were delayed due to slower than expected drilling. An additional well was spud in October, 2002 and two wells will now be completed in December. Commercial development plans continued on the Baobab field.

- Successfully negotiated a 50% working interest and operatorship for Block 16 located offshore Angola. This high risk/high potential exploration block is located in one of the world's most prospective oil basins.

- Successfully completed a United States debt offering of US $350 million of 10-year notes at an interest rate of 5.45% and US $350 million of 31-year notes at an interest rate of 6.45%.

ADJUSTED NET EARNINGS

The following reconciliation lists the after-tax effects of certain items for each of the periods reported.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	**JUN 30 2002**	**SEP 30 2001**	**SEP 30 2002**	**SEP 30 2001**
($ millions, except per share amounts)					
Net earnings attributable to common shareholders as reported	**$ 117**	$ 145	$ 81	**$ 362**	$ 590
Unrealized foreign exchange loss (gain) [1]	**42**	(64)	57	**(35)**	61
Unrealized foreign exchange loss (gain) on preferred securities[1]	**5**	(6)	5	**(1)**	6
Effect of statutory tax rate changes on future income tax liabilities[2]	**-**	13	-	**13**	(46)
Reduction in carrying value of foreign assets[3]	**-**	30	-	**30**	-
Adjusted net earnings attributable to common shareholders	**$ 164**	$ 118	$ 143	**$ 369**	$ 611
Per share – basic	**$ 1.23**	$ 0.96	$ 1.18	**$ 2.93**	$ 5.03
– diluted	**$ 1.20**	$ 0.88	$ 1.16	**$ 2.83**	$ 4.89

(1) *Gains and losses on the translation of long-term debt and preferred securities to period end exchange rates are immediately recognized in net earnings attributable to common shareholders.*

(2) *All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax liabilities. The impact of these tax rate changes are recorded in net earnings during the period the legislation is substantively enacted. During the second quarter of 2002, the United Kingdom increased income taxes applicable to the oil and natural gas industry and a Canadian province reduced corporate income tax rates.*

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

OPERATIONS REVIEW

Production

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.

Third quarter 2002 natural gas production averaged 1,427 mmcf/d, an increase of 54% from the third quarter of 2001 and a 32% increase from the second quarter of 2002. Natural gas production accounted for 50% of the Company's production this quarter and reflected the July 1, 2002 acquisition of Rio Alto and the commencement of natural declines at Ladyfern. Production from properties owned by Rio Alto at the time of the acquisition was 410 mmcf/d and after the effect of normal depletion exited the quarter at 384 mmcf/d. Ladyfern production declined from an average of 201 mmcf/d in the second quarter of 2002 to 178 mmcf/d during the third quarter. The Company currently expects this field to continue declines in the order of 70% through 2003. This steep decline commenced in late August as pressures declined and the most down-dip well in the pool watered out. Water encroachment continues into a second well, with the effect that significant declines continue and current production, net to Canadian Natural, of 130 - 140 mmcf/d. Canadian Natural expected such declines to occur, but was unsure of the timing and magnitude of the water influx, which in formations such as the Slave Point is difficult to forecast. The Company purposefully reduced 2002 natural gas drilling activity to build drilling prospect inventory to offset these anticipated declines. Access to many parts of the western Canadian natural gas basin is possible in winter months only, precluding an acceleration of replacement drilling. The following schedule provides a summary of natural gas production:

Natural Gas Production Levels

		Daily Production (mmcf/d)
Third quarter 2002 opening volume		1,071
Additions:	Volume additions through drilling and recompletions	69
	Rio Alto acquisition	410
Declines:	Normal decline in base production	(50)
	Normal decline in Rio Alto properties	(26)
	Ladyfern declines	(54)
Third quarter 2002 exit volume		1,420

Production of oil and liquids in the third quarter of 2002 was 28% higher than the previous quarter and 17% higher than the corresponding period of last year. Increases in North America reflected additional heavy oil drilling activity and acquired production. North Sea volumes increased both as a result of the acquisition of additional interests in the northern sector of the North Sea and the correction of a pipeline blockage at the Kyle field. Offshore West Africa volumes increased as one additional producing well was brought on-stream at the Espoir field.

The Company's production composition is as follows:

	Q3 2002		**Q2 2002**		**Q3 2001**	
	mboe/d	*%*	*mboe/d*	*%*	*mboe/d*	*%*
Natural gas	**237.9**	**50**	179.6	49	154.0	43
Light oil and NGLs	**102.8**	**21**	70.1	19	77.7	21
Pelican Lake oil	**32.0**	**7**	30.8	8	34.4	10
Primary heavy oil	**66.9**	**14**	51.3	14	58.1	16
Thermal heavy oil	**40.3**	**8**	37.2	10	36.8	10
	479.9	**100**	369.0	100	361.0	100

The Company expects production levels in the fourth quarter of 2002 to average 1,350 to 1,365 mmcf/d of natural gas and 240 to 250 mbbls/d of oil and liquids. This results in expected annual 2002 production levels of approximately 1,230 mmcf/d of natural gas (2001 – 918 mmcf/d) and approximately 216 mbbls/d of oil and liquids (2001 – 206 mbbls/d).

DRILLING ACTIVITY *(number of wells)*

	NINE MONTHS ENDED SEPTEMBER 30			
	2002		2001	
	Gross	**Net**	**Gross**	**Net**
Oil	**290**	**253**	264	228
Natural gas	**165**	**150**	541	460
Dry	**27**	**23**	38	32
Subtotal	**482**	**426**	843	720
Injection/strat tests	**416**	**408**	251	250
Total	**898**	**834**	1,094	970
Success rate *(excluding injection/strat tests)*		**95%**		96%

Canadian Natural drilled 60 net oil wells and 27 net natural gas wells during the third quarter of 2002. These wells were concentrated in the Company's heavy oil areas of North Alberta/West Saskatchewan, the light oil areas of Southeast Saskatchewan and its four natural gas core areas. The total success rate for Canadian Natural's drilling program was 97% during the third quarter, excluding injection/stratigraphic test wells.

The number of net wells drilled during the first nine months of the year (excluding injection/stratigraphic test wells) decreased 41% from the prior year, comprised of a 67% reduction in natural gas well drilling and an 11% increase in oil well drilling. The decrease in natural gas drilling reflects the Company's decision to defer natural gas drilling to offset anticipated future Ladyfern production declines and reflects its capital allocation policy which opportunistically has shifted additional capital into heavy oil drilling to take advantage of favourable market pricing.

During the first nine months of the year, the Company drilled 408 net injection/stratigraphic test wells on the oil sands leases in the Horizon Oil Sands Project and in North Alberta/West Saskatchewan.

Pricing

Netbacks received for Canadian Natural's heavy oil and Pelican Lake oil production improved significantly over the last year due to both higher WTI pricing and the narrowing of price differentials to WTI. Canadian Natural expects these heavy oil differentials to widen during the fourth quarter due to seasonality and additional production from western Canada. This differential is still expected to be significantly lower, however, than differentials experienced during the fourth quarter of 2001 when a refinery closure resulted in reduced heavy oil demand.

In 2003, as part of its overall risk management program, the Company has placed costless collars on a portion of its oil production. During January to June, 2003 sales of a total of 104,000 bbls/d are subject to a floor price of US $22.09 with a ceiling price of US $27.26. In July and August, 2003 sales of a total of 60,000 bbls/d are subject to a floor price of US $23.00 with a ceiling price of US $27.85.

During the third quarter of 2002 natural gas pricing in Canada was subject to abnormally high differentials to NYMEX benchmark pricing. This was the result of common carrier pipeline maintenance activities and its subsequent impact on exports of natural gas to the United States.

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

	Pricing Indications as at Nov 4, 2002	Q3 2002	Q2 2002	Q3 2001
WTI benchmark price *(US $/bbl)*	**$ 26.95**	**$ 28.25**	$ 26.26	$ 26.57
Differential to LLB blend *(US $/bbl)*	**$ 8.44**	**$ 5.97**	$ 6.04	$ 8.10
Condensate benchmark price *(US $/bbl)*	**$ 27.78**	**$ 28.14**	$ 26.36	$ 26.70
NYMEX benchmark price *(US $/mmbtu)*	**$ 3.87**	**$ 3.26**	$ 3.37	$ 2.99
AECO benchmark price *(Cdn $/mmbtu)*	**$ 5.31**	**$ 3.25**	$ 4.43	$ 3.93
Canadian Natural's Wellhead Price[1]				
Light oil and NGLs *(Cdn $/bbl)*	**$ 36.07**	**$ 34.36**	$ 31.90	$ 35.03
Pelican Lake oil *(Cdn $/bbl)*	**$ 23.71**	**$ 30.58**	$ 25.05	$ 24.99
Primary heavy oil *(Cdn $/bbl)*	**$ 23.10**	**$ 30.11**	$ 24.54	$ 23.69
Thermal heavy oil *(Cdn $/bbl)*	**$ 22.58**	**$ 29.23**	$ 23.73	$ 22.46
Natural gas *(Cdn $/mcf)*	**$ 4.96**	**$ 3.15**	$ 3.72	$ 3.12

[1] *Including financial instruments.*

ACTIVITY BY CORE REGION

	Net Undeveloped Land As at September 30, 2002 *(thousands of net acres)*	Drilling Activity Period ended September 30, 2002 *(net wells)*
Northeast British Columbia	**1,393**	**43**
Northwest Alberta	**1,952**	**11**
North Alberta/West Saskatchewan	**4,261**	**464**
Horizon Oil Sands	**237**	**256**
South Alberta	**889**	**50**
Southeast Saskatchewan	**166**	**5**
United Kingdom North Sea	**401**	**2**
Offshore West Africa	**1,862**	**3**

2003 Budget

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

Canadian Natural is presently budgeting a cash flow from operations in 2003 of $2,350 million to $2,500 million. This cash flow is derived from production of 1,280 to 1,330 mmcf/d of natural gas and 240,000 to 260,000 bbls/d of oil and liquids, and applying the current strip pricing parameters averaging WTI price of US $24.00, a WTI to LLB oil differential price of US $8.50 and an AECO natural gas price of $5.20 per mcf.

The budgeted capital expenditures in 2003 are currently expected to be as follows:

($ millions)		2003
Canadian natural gas properties	$	**691**
Canadian oil properties		**517**
Horizon oil sands		**211**
International oil properties – United Kingdom		**281**
International oil properties – Offshore West Africa		**280**
Property acquisitions		**300**
	$	**2,280**

North America Conventional

As a result of 2002's strong Ladyfern production increases during the first half of the year, Canadian Natural reduced current year 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.

Canadian Natural plans to continue its exploration program in deeper formations in Northeast British Columbia, including the Slave Point trend, where two and possibly three wells will be drilled during the winter of 2003. The Slave Point horizon is technically complex making it a high-risk exploration target. Canadian Natural's exploration activities benefit from owning the area's largest database of 2-D and 3-D seismic information and from its extensive landholdings in the region.

The acquisition of Rio Alto effective July 1, 2002 provides 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 will commence development of this land in the first quarter of 2003 with the drilling of up to 52 wells. Approximately 17 wells will target the Cardium zone which is a complex geological zone requiring both horizontal and vertical wells to test the production capabilities of the formation.

During 2002 Canadian Natural drastically reduced the number of natural gas wells drilled from 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 experimental Pelican Lake emulsion flood continued to meet expectations during the third quarter, with injections continuing since early April 2002. If successful, this project will substantially increase the recovery factor from the thin Pelican Lake sands. 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. Based upon positive laboratory testing, this project could double or triple recovery factors if the technology can be implemented in the field. Data will continue to be gathered on the success of this test throughout the last half of 2002. The Company plans to optimize the emulsion project with a demonstration project during 2003.

Canadian Natural recently received regulatory approval to utilize high pressure steaming at its thermal oil project at Primrose in eastern Alberta. In 2003, two new pads containing a total of 24 wells each incorporating high pressure steaming will be drilled on these lands. Steaming of these wells will commence in the third quarter of 2003 with initial oil production following in mid 2004.

North America Horizon Oil Sands Project

Following filing at the end of June of the Horizon Oil Sands project for regulatory approvals, Canadian Natural commenced the Design Basis Memorandum which is the second of the three phases of engineering design work.

It is currently anticipated that the Design Basis Memorandum will be completed during the first quarter of 2003, at which point a decision to commence Engineering Design Specifications ("EDS") will be made. Given current uncertainty surrounding implementation of the Kyoto protocol by the Canadian Government, and any specific terms thereof, a limited form of EDS or a major scope change to use facilities outside of Canada may be initiated. At this time, Canadian Natural has reduced its planned 2003 capital expenditures on the Horizon Project by $100 million pending the clarification of the implementation of the Kyoto protocol. The impact of a limited form of EDS or scope change would likely defer commencement of first production by one year to late 2008. A slowed-EDS, however, would enable the Company to achieve detailed engineering design in excess of its targeted 85% prior to the start of construction, further reducing risk of construction cost overruns.

United Kingdom

During the quarter Canadian Natural completed a property acquisition in the northern North Sea that increased ownership levels in the Ninian, Murchison, Lyell and Columba Terraces fields. Canadian Natural is now operator designee on each of these fields. As part of the transaction the Company also received an interest in the Strathspey field and 12 licences covering 20 exploration blocks and part blocks surrounding the Ninian and Murchison platforms. Increased ownership in related pipeline and terminaling infrastructure was also acquired. Ownership and operatorship levels are now similar in the North Sea to those levels found throughout Canadian Natural's other worldwide investments.

In the central North Sea, the blockage in the Kyle export natural gas pipeline was repaired and production was restored in July, 2002. One additional well at Banff, where Canadian Natural holds a 56% working interest, is currently drilling.

In 2003, Canadian Natural has budgeted to spend a total of $281 million on its international holdings in the United Kingdom. These funds will be directed towards drilling of an additional 17 wells in the northern North Sea and one additional well in the central North Sea. Other exploitation and waterflood optimization programs will also be carried out in both areas to increase the productivity and recovery factors in these known pools of light oil.

Offshore West Africa

During the quarter, Canadian Natural continued the development of the 59% owned and operated Espoir field located offshore Côte d'Ivoire with the drilling and completion of the third producing well in the field. Additional producing wells were expected to be onstream by the fourth quarter of the year, however slower drilling of the fourth producing well in the field caused by drilling in unanticipated uphole faults has delayed completion of the development program. The fifth producer well has been spud, and it and the fourth producer will be completed and tied in during the fourth quarter of 2002. The delay in these wells in turn delays completion of additional producer and injector wells. Inability to ramp up injectivity results in a slower build up of waterflood pressures in the upper zones. Perforation of this upper zone is correspondingly delayed until later in 2003.

Canadian Natural is proceeding with development plans on the Baobab field located offshore Côte d'Ivoire. While determination of optimum facilities size continues, it is anticipated that gross production in the range of 50-65 mbbls/d of oil to a new FPSO could commence in late 2004/early 2005. Field development plans have been submitted to the Government with finalization expected in the next few months.

Political unrest in Côte d'Ivoire during the third quarter has had no impact on the Company's operations. The Company has developed contingency plans to continue Côte d'Ivoire operations from another nearby country. It is important to note that insurrections to date have largely been concentrated in the northern areas of the country, far away from the Company's offshore development and far from Abidjan, where the Company's offices are located.

Canadian Natural's 2003 expenditure budget forecasts expenditures totaling $280 million in offshore West Africa. Expenditures incurred in Côte d'Ivoire of $220 million will result in the finalization of drilling and completion operations at Espoir, an exploration well at Acajou, and finalization of development plans and fourth quarter drilling at Baobab. In Angola, Canadian Natural has budgeted the drilling of a well in newly acquired Block 16 commencing in the third quarter.

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.

In September, the Company issued US $350 million of 10-year, 5.45% unsecured notes and US $350 million of 31-year, 6.45% unsecured notes to purchasers in the United States. The proceeds from the sale of the notes were used primarily to repay bank indebtedness. The securities were rated “Baa1” by Moody’s Investors Service, Inc., “BBB+” by Standard & Poor’s Corporation and “BBB (high)” by Dominion Bond Rating Service Limited. The notes were issued under the short form base shelf prospectus dated August 16, 2002, which allows for the issuance of debt securities in an aggregate principal amount of up to US $1 billion.

Following these issues of debt securities the Company had:

- Approximately $1.3 billion of available unused bank credit lines.
- Fixed/floating interest rate mix of 47/53.
- An overall average borrowing cost of approximately 4.5% for the third quarter of 2002.
- 73% of borrowings denominated in US $.
- Non-bank based borrowings of 75% of total long-term debt.

Long-term debt at September 30, 2002 amounted to $4.2 billion and reflected a 2.3x debt to cash flow ratio and a debt to book capitalization of 47.2%. This increase in debt reflects the third quarter acquisition of Rio Alto and excludes the cash flows and earnings prior to June 30, 2002.

The ratings for our debt securities and our relationships with our principal banks are extremely important to us as we continue to expand and grow the Company. Therefore, we will continually undertake to strengthen our balance sheet and financial position.

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 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 regular fourth quarter dividend payment will occur on January 1, 2003 and will be made to shareholders of record at the close of business on December 13, 2002.

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 nine months ended September 30, 2002 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2001.

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.

ACQUISITIONS

Effective July 1, 2002, the Company paid cash of $850.0 million and issued 10,008,000 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. Also effective July 1, 2002, the Company acquired certain northern North Sea assets in the United Kingdom for cash consideration of US $120.0 million and the Company's 5% interest in the Harding field. These acquisitions are included in the results of operations commencing July 1, 2002.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001[1]	**SEP 30 2002**	SEP 30 2001[1]
FINANCIAL HIGHLIGHTS *($ millions, except per share amounts)*					
Revenue	**$ 1,173**	$ 863	$ 811	**$ 2,753**	$ 2,922
Cash flow from operations attributable to common shareholders[2]	**$ 644**	$ 475	$ 437	**$ 1,477**	$ 1,594
Per share – basic	**$ 4.83**	$ 3.86	$ 3.62	**$ 11.73**	$ 13.14
– diluted	**$ 4.71**	$ 3.70	$ 3.54	**$ 11.28**	$ 12.61
Net earnings attributable to common shareholders[3]	**$ 117**	$ 145	$ 81	**$ 362**	$ 590
Per share – basic	**$ 0.88**	$ 1.18	$ 0.67	**$ 2.87**	$ 4.86
– diluted	**$ 0.86**	$ 1.09	$ 0.66	**$ 2.78**	$ 4.72
Acquisition of Rio Alto	**$ 2,309**	$ -	$ -	**$ 2,309**	$ -
Capital expenditures, net of dispositions	**$ 621**	$ 305	$ 352	**$ 1,384**	$ 1,355

(1) *Restated for change in accounting policy (see consolidated financial statement notes 1 and 2).*
(2) *After dividend on preferred securities.*
(3) *After dividend and revaluation of preferred securities.*

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	**JUN 30 2002**	**SEP 30 2001[1]**	**SEP 30 2002**	**SEP 30 2001[1]**
OPERATING HIGHLIGHTS					
Oil and liquids *($/bbl, except daily production)*					
Daily production *(bbls/d)*	**242,051**	189,386	207,065	**206,822**	209,128
Sales price	**$ 33.57**	$ 28.27	$ 28.37	**$ 29.23**	$ 25.28
Royalties	**3.56**	3.02	2.47	**3.01**	2.41
Production expense	**8.67**	7.95	7.29	**8.19**	7.68
Netback	**$ 21.34**	$ 17.30	$ 18.61	**$ 18.03**	$ 15.19
Natural gas *($/mcf, except daily production)*					
Daily production *(mmcf/d)*	**1,427**	1,078	924	**1,188**	887
Sales price	**$ 3.13**	$ 3.68	$ 3.12	**$ 3.28**	$ 6.01
Royalties	**0.67**	0.77	0.67	**0.67**	1.49
Production expense	**0.55**	0.57	0.50	**0.57**	0.50
Netback	**$ 1.91**	$ 2.34	$ 1.95	**$ 2.04**	$ 4.02
Barrels of oil equivalent *($/boe, except daily production)*					
Daily production *(boe/d)*	**479,949**	369,022	361,029	**404,745**	356,905
Sales price	**$ 26.26**	$ 25.29	$ 24.25	**$ 24.57**	$ 29.76
Royalties	**3.80**	3.79	3.14	**3.49**	5.10
Production expense	**6.01**	5.76	5.47	**5.85**	5.75
Netback	**$ 16.45**	$ 15.74	$ 15.64	**$ 15.23**	$ 18.91

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

Cash flow and net earnings for the three months ended September 30, 2002 increased from the comparable period in 2001 due to increased production, higher product prices and lower current income tax in the North Sea. These factors were partially offset by higher oil hedging losses, higher royalties and higher production expense as well as increased administration and interest expenses. Net earnings was also impacted by higher depletion, depreciation and amortization costs and higher future income tax expense. Third quarter cash flow increased from the second quarter due to increased production and higher oil and liquids prices. Net earnings for the quarter decreased from the prior quarter due to higher depletion, depreciation and amortization costs and the effects of the fluctuating Canadian dollar, resulting in unrealized foreign exchange losses on the Company's US dollar denominated debt. Year-to-date cash flow and net earnings decreased from the comparable period in 2001 due to lower natural gas prices, higher production expense and higher administration costs. Net earnings was also impacted by higher depletion, depreciation and amortization costs, but was partially offset by unrealized foreign exchange gains on the Company's US dollar denominated debt.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	**JUN 30 2002**	**SEP 30 2001**	**SEP 30 2002**	**SEP 30 2001**
DAILY PRODUCTION					
Oil and liquids *(bbls/d)*					
North America	**185,990**	158,196	162,890	**165,608**	169,261
North Sea	**47,114**	25,685	40,356	**34,629**	36,422
Offshore West Africa	**8,947**	5,505	3,819	**6,585**	3,445
Total	**242,051**	189,386	207,065	**206,822**	209,128
Natural gas *(mmcf/d)*					
North America	**1,395**	1,058	906	**1,162**	877
North Sea	**29**	20	18	**25**	10
Offshore West Africa	**3**	-	-	**1**	-
Total	**1,427**	1,078	924	**1,188**	887
Product mix					
Light oil and NGLs	**21.4%**	19.0%	21.5%	**20.2%**	20.9%
Pelican Lake oil	**6.7%**	8.3%	9.5%	**7.4%**	10.1%
Primary heavy oil	**13.9%**	13.9%	16.1%	**13.7%**	16.2%
Thermal heavy oil	**8.4%**	10.1%	10.2%	**9.8%**	11.4%
Natural gas	**49.6%**	48.7%	42.7%	**48.9%**	41.4%

North America oil and liquids production increased for the three months ended September 30, 2002 over the comparable periods due to the acquisition of Rio Alto and the acquisition of additional producing heavy oil properties in eastern Alberta. Oil and liquids production also increased due to an active drilling program in the second and third quarter 2002 focusing on heavy oil and Pelican Lake properties. North Sea oil production increased from the comparable three-month periods due to the acquisition of additional interests in the Ninian, Murchison, Lyell and Columba fields in exchange for US $120.0 million and the Company's interest in the Harding field (see discussion of capital expenditures). Oil production from the Kyle field increased from the prior quarter as a result of rectifying a pipeline blockage in the export natural gas pipeline downstream of the Curlew floating production, storage and offtake vessel in early July 2002. Oil production from the Kyle field was restricted for most of the second quarter 2002 because of the blockage. The increase in North Sea oil production was partially offset by planned maintenance shutdowns of the Ninian North and Ninian Central platforms during August. Offshore West Africa oil production increased from the comparable periods as a result of production commencing from the Company's operated Espoir field, located offshore Côte d'Ivoire, in February 2002. The third producer well commenced production in early July. Production from this field is anticipated to increase over the next several months as additional wells are drilled during the first phase of development.

Natural gas production increased overall and in the North America segment from comparable periods due to the acquisition of Rio Alto. North American natural gas production also increased year-over-year as a result of the focus of the 2001 capital expenditure program on natural gas development, which resulted in the development of the Ladyfern field. Production from Ladyfern averaged 182 mmcf/d for the first nine months of 2002. Natural gas production from the Ladyfern field decreased from an average of 201 mmcf/d in the second quarter of 2002 to 178 mmcf/d during the third quarter. Current production from Ladyfern is approximately 135 mmcf/d and the Company expects a 70% decline rate through 2003. Production of natural gas in the North Sea increased from the previous quarter due to the rectification of the pipeline blockage impacting production from the Kyle field.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001	SEP 30 2002	SEP 30 2001
PRODUCT PRICES					
Oil and liquids *($/bbl)*					
North America	**$ 31.07**	$ 26.27	$ 26.02	**$ 26.85**	$ 21.77
North Sea	**$ 41.68**	$ 39.36	$ 37.28	**$ 38.77**	$ 40.41
Offshore West Africa	**$ 42.78**	$ 33.92	$ 34.66	**$ 38.95**	$ 38.03
Company average	**$ 33.57**	$ 28.27	$ 28.37	**$ 29.23**	$ 25.28
Natural gas *($/mcf)*					
North America	**$ 3.15**	$ 3.72	$ 3.13	**$ 3.29**	$ 6.05
North Sea	**$ 1.98**	$ 1.80	$ 2.51	**$ 2.56**	$ 2.21
Offshore West Africa	**$ 4.97**	$ -	$ -	**$ 4.97**	$ -
Company average	**$ 3.13**	$ 3.68	$ 3.12	**$ 3.28**	$ 6.01
Percentage of revenue					
Oil and liquids	**64.6%**	57.5%	67.1%	**60.9%**	49.8%
Natural gas	**35.4%**	42.5%	32.9%	**39.1%**	50.2%

The North American realized oil and liquids price for the nine months ended September 30, 2002 increased from the comparable period in 2001 primarily as a result of narrower heavy oil differentials. Heavy oil differentials averaged US $5.91 per bbl in the first nine months of 2002 compared to US $10.93 per bbl for the first nine months of 2001. The narrowing of the heavy oil differentials is due to supply and demand fundamentals as well as the recommencement of a heavy oil refinery in the US Midwest in the second quarter of 2002. The third quarter 2002 North American realized oil and liquids price increased from the comparable periods due to higher worldwide oil prices. West Texas Intermediate ("WTI") averaged US $28.25 per bbl for the quarter ended September 30, 2002 compared to US $26.26 per bbl and US $26.57 per bbl for the quarters ended June 30, 2002 and September 30, 2001, respectively. North Sea and offshore West Africa oil prices increased from the comparable three-month periods due to the strengthening of oil prices.

Natural gas prices in North America for the third quarter ended September 30, 2002 decreased from the previous quarter due to lower AECO prices. Natural gas prices were impacted in the quarter by restrictions on export capacity out of Alberta due to temporary anomalies resulting from maintenance downtime on common carrier pipeline systems. AECO prices decreased 27% in the third quarter 2002 to average $3.25 per mmbtu compared to $4.43 per mmbtu in the second quarter 2002. The Company expects natural gas prices to increase due to the impact that reduced drilling levels will have on supply and as North American storage levels and weather patterns return to normal. Natural gas prices for the nine months ended September 30, 2002 decreased from the comparable period due to lower demand in the North American market and warmer than average winter temperatures, which resulted in higher natural gas storage levels. AECO prices averaged $3.68 per mmbtu for the first nine months of 2002 compared to $7.27 per mmbtu for the first nine months of 2001.

The Company enters into various financial instruments to protect the downside prices received on the sale of a portion of its oil and natural gas production. The price realized from the sale of oil was reduced by $1.62 per bbl in the quarter ended September 30, 2002 ($1.85 per bbl and $0.22 per bbl reductions, respectively, in the quarters ended June 30, 2002 and September 30, 2001). The price realized from the sale of natural gas was increased by $0.05 per mcf in the third quarter of 2002 ($0.09 per mcf and $0.10 per mcf reductions, respectively, in the quarters ended June 30, 2002 and September 30, 2001).

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	**JUN 30 2002**	**SEP 30 2001**	**SEP 30 2002**	**SEP 30 2001**
ROYALTIES					
Oil and liquids *($/bbl)*					
North America	**$ 3.92**	$ 3.29	$ 2.61	**$ 3.28**	$ 2.47
North Sea	**$ 2.56**	$ 1.76	$ 1.97	**$ 2.06**	$ 2.29
Offshore West Africa	**$ 1.34**	$ 1.11	$ 2.03	**$ 1.36**	$ 1.02
Company average	**$ 3.56**	$ 3.02	$ 2.47	**$ 3.01**	$ 2.41
Natural gas *($/mcf)*					
North America	**$ 0.69**	$ 0.79	$ 0.68	**$ 0.68**	$ 1.50
Offshore West Africa	**$ 0.15**	$ -	$ -	**$ 0.15**	$ -
Company average	**$ 0.67**	$ 0.77	$ 0.67	**$ 0.67**	$ 1.49
Company average *($/boe)*	**$ 3.80**	$ 3.79	$ 3.14	**$ 3.49**	$ 5.10
Percentage of revenue *(excluding financial instruments)*					
Oil and liquids	**10.1%**	10.0%	8.7%	**9.8%**	9.5%
Natural gas	**21.8%**	20.4%	20.8%	**20.4%**	23.2%

Oil and liquids royalties in North America increased over the comparable periods due to higher product prices. North America oil and liquids royalties also increased due to some heavy oil projects reaching payout and no longer qualifying for reduced royalty rates. North Sea oil royalties increased for the three months ended September 30, 2002 from the prior quarter and comparable period in 2001 due to the acquisition of additional interests in the royalty paying Ninian, Murchison and Columba fields. North Sea oil royalties for the nine months ended September 30, 2002 decreased from the comparable period in 2001 due to lower world oil prices. Offshore West Africa oil royalties decreased in the third quarter of 2002 from the comparable period in 2001 as a result of production ceasing from the higher royalty rate Kiame field in April 2002. Oil royalties for offshore West Africa increased in the third quarter of 2002 compared to the second quarter 2002 due to higher world oil prices. Offshore West Africa oil royalties for the nine months ended September 30, 2002 increased from the comparable periods in 2001 due to the Kiame field not being subject to royalties for a portion of 2001. The Kiame field was the only field on production in 2001 in this segment.

North American natural gas royalties changed from the comparable periods as a result of fluctuations in the sales price of natural gas. Natural gas royalties as a percentage of revenue increased from the comparable three-month periods due to Rio Alto properties having a larger proportion of their production subject to crown royalties, which have a higher royalty rate compared to freehold royalties.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001[1]	SEP 30 2002	SEP 30 2001[1]
PRODUCTION EXPENSE					
Oil and liquids *($/bbl)*					
North America	**$ 6.10**	$ 6.52	$ 6.82	**$ 6.50**	$ 7.20
North Sea	**$ 18.30**	$ 15.72	$ 8.09	**$ 15.25**	$ 8.50
Offshore West Africa	**$ 11.23**	$ 12.76	$ 19.05	**$ 13.60**	$ 22.61
Company average	**$ 8.67**	$ 7.95	$ 7.29	**$ 8.19**	$ 7.68
Natural gas *($/mcf)*					
North America	**$ 0.52**	$ 0.55	$ 0.50	**$ 0.54**	$ 0.50
North Sea	**$ 1.78**	$ 1.90	$ 0.74	**$ 1.65**	$ 0.69
Offshore West Africa	**$ 1.77**	$ -	$ -	**$ 1.77**	$ -
Company average	**$ 0.55**	$ 0.57	$ 0.50	**$ 0.57**	$ 0.50
Company average *($/boe)*	**$ 6.01**	$ 5.76	$ 5.47	**$ 5.85**	$ 5.75

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

North American oil and liquids production expense decreased from the comparable periods due to lower costs of natural gas, which is used to produce the steam to heat thermal heavy oil formations. Oil and liquids production expense also decreased in North America from the prior quarter due to the allocation of fixed costs over greater production volumes. North Sea oil production expense increased over the comparable periods due to costs associated with planned maintenance shutdowns of the Ninian North and Ninian Central platforms during August. These maintenance shutdowns reduced production volumes and increased production expenses during the quarter. Offshore West Africa oil production expense decreased from the comparable periods due to increased production from the Espoir field and production ceasing from the higher production expense Kiame field.

Natural gas production expense in North America increased over the comparable periods in 2001 due to an increase in the toll rates and the percentage of natural gas produced through the gathering and processing system in British Columbia. Natural gas production expense decreased in the third quarter of 2002 from the second quarter of 2002 due to the acquisition of Rio Alto, which has lower natural gas production expenses, and as a result of the expiry of the Ladyfern McMahon service fee at the end of June 2002.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001	SEP 30 2002	SEP 30 2001
DEPLETION, DEPRECIATION AND AMORTIZATION[1]					
Expense *($ millions)*	**$ 401.1**	$ 289.3	$ 235.3	**$ 922.4**	$ 658.8
$/boe	**$ 9.08**	$ 8.61	$ 7.09	**$ 8.35**	$ 6.76

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

Depletion, depreciation and amortization ("DD&A") increased for the three and nine months ended September 30, 2002 over the comparable periods due to the allocation of fair values to Rio Alto capital assets and future abandonment costs associated with the acquisition of additional interests in the North Sea. DD&A also increased for the nine months ended September 30, 2002 over the comparable 2001 period as a result of the Company's decision to exit from its interests in Block 19 in Angola and in the Aje field in Nigeria. The Company wrote off all related capitalized costs in those countries, totaling $51 million, in the second quarter of 2002.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001	SEP 30 2002	SEP 30 2001
ADMINISTRATION EXPENSE					
Net expense *($ millions)*	**$ 17.8**	$ 12.3	$ 9.4	**$ 43.6**	$ 25.6
$/boe	**$ 0.40**	$ 0.37	$ 0.28	**$ 0.39**	$ 0.26

The Company's administration expense increased from the comparable periods mainly due to higher staffing levels associated with the growth in production and the expanding asset base.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001	SEP 30 2002	SEP 30 2001
INTEREST EXPENSE					
Interest expense *($ millions)*	**$ 48.9**	$ 28.6	$ 32.2	**$ 106.2**	$ 106.4
$/boe	**$ 1.11**	$ 0.85	$ 0.97	**$ 0.96**	$ 1.09
Average effective interest rate	**4.5%**	4.4%	5.4%	**4.3%**	5.7%

Interest expense for the three months ended September 30, 2002 increased from the comparable periods due to higher average outstanding debt levels associated with the acquisition of Rio Alto. Interest expense for the nine months ended September 30, 2002 remained consistent with the previous year as a result of the impact of lower effective interest rates offset by higher debt levels.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001	SEP 30 2002	SEP 30 2001
MIDSTREAM *($ millions)*					
Revenue	**$ 13.3**	$ 13.5	$ 5.0	**$ 37.2**	$ 22.5
Operating costs	**3.1**	3.4	1.3	**9.6**	8.3
Cash flow	**10.2**	10.1	3.7	**27.6**	14.2
Depreciation	**1.9**	1.9	0.9	**5.7**	2.6
Segment earnings before taxes	**$ 8.3**	$ 8.2	$ 2.8	**$ 21.9**	$ 11.6

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. Through these assets, the Company transports approximately 85% of its heavy oil 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.

Revenue from midstream assets increased from the comparable periods in 2001 due to the expansion of the ECHO pipeline and the commencement of operations from the Cold Lake pipeline system in late December 2001. The increased pipeline revenues are partially offset by the decline in electricity revenue. Electricity revenues declined over the same period in 2001 due to lower prices received.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	JUN 30 2002	SEP 30 2001	SEP 30 2002	SEP 30 2001
TAXES					
Taxes other than income tax *($ millions)*					
Current	**$ 13.0**	$ 11.8	$ 21.1	**$ 38.3**	$ 59.2
Deferred	**0.6**	1.6	(1.3)	**3.6**	(1.2)
Total	**$ 13.6**	$ 13.4	$ 19.8	**$ 41.9**	$ 58.0
Current income tax *($ millions)*					
North Sea	**$ 3.0**	$ 2.3	$ 16.5	**$ 16.3**	$ 51.5
Offshore West Africa	**3.7**	1.1	-	**5.3**	-
Large Corporations Tax	**5.6**	4.5	3.2	**14.4**	10.4
Total	**$ 12.3**	$ 7.9	$ 19.7	**$ 36.0**	$ 61.9
Future income tax *($ millions)*	**$ 76.4**	$ 107.9	$ 61.0	**$ 222.6**	$ 280.7
Effective income tax rate	**41.7%**	45.1%	40.4%	**41.5%**	31.9%

Taxes other than income tax consist of current and deferred petroleum revenue tax, other international taxes and provincial resource surcharges. The fluctuations in taxes other than income tax from comparable periods is due to the fluctuations in world oil prices, primarily in the North Sea.

North Sea current income tax expense for the nine months ended September 30, 2002 decreased from the comparable period in 2001 due to decreased earnings before taxes. Current income tax in the North Sea also decreased due to the UK Government increasing the first year capital allowance rate for plant and machinery expenditures to 100% from the previous rate of 25% during the second quarter of 2002. Current income tax expense in the third quarter 2002 increased from the prior quarter due to higher taxable income. Offshore West Africa current income tax increased from the comparable periods due to increased production and higher worldwide oil prices. 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.

Future income tax expense decreased from the prior quarter as a result of the inclusion in the second quarter 2002 of the effects of increased tax rates on profits from North Sea oil and natural gas production. A 10% supplementary charge, in addition to the current corporate tax rate of 30%, took effect April 17, 2002 and excludes any deduction for financing costs. The implementation of the supplementary charge resulted in a one-time increase in the UK future income tax liability of $34 million in the second quarter of 2002. The increase in future income tax expense in the second quarter of 2002 was partially offset by a $21 million reduction in the future income tax liability as a result of a decrease in a Canadian province's corporate income tax rate. The Company's future income taxes payable and property, plant and equipment have been increased by $39 million to provide for the exchange of non-tax base assets in the North Sea for the first nine months of 2002.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	**JUN 30 2002**	**SEP 30 2001(1)**	**SEP 30 2002**	**SEP 30 2001(1)**
CAPITAL EXPENDITURES *($ millions)*					
Acquisition of Rio Alto	**$ 2,308.7**	$ -	$ -	**$ 2,308.7**	$ -
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 333.3**	$ 33.1	$ 24.6	**$ 401.7**	$ 270.8
Land acquisition and retention	**48.4**	19.2	35.8	**95.4**	85.0
Seismic evaluations	**4.9**	14.6	8.6	**44.3**	65.8
Well drilling, completion and equipping	**144.1**	135.9	148.6	**486.8**	528.8
Pipeline and production facilities	**56.5**	66.6	109.7	**247.4**	326.1
Total net reserve replacement expenditures	**587.2**	269.4	327.3	**1,275.6**	1,276.5
Project Horizon	**9.9**	16.6	1.9	**48.8**	15.8
Midstream	**-**	5.2	16.1	**14.8**	51.8
Abandonments	**19.8**	11.9	5.0	**38.5**	6.0
Head office	**3.9**	1.7	1.8	**6.7**	4.7
Total net capital expenditures	**$ 620.8**	$ 304.8	$ 352.1	**$ 1,384.4**	$ 1,354.8
By segment (excluding Acquisition of Rio Alto)					
North America	**$ 331.8**	$ 232.5	$ 280.9	**$ 984.4**	$ 1,078.7
North Sea	**230.2**	13.2	32.2	**212.0**	63.5
Offshore West Africa	**58.8**	53.9	22.9	**173.2**	160.8
Midstream	**-**	5.2	16.1	**14.8**	51.8
Total	**$ 620.8**	$ 304.8	$ 352.1	**$ 1,384.4**	$ 1,354.8

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

North America capital expenditures during the third quarter 2002 include the acquisition of Rio Alto and additional producing and non-producing heavy oil properties, primarily in the Lindbergh area of eastern Alberta. The Rio Alto acquisition provides the Company with a new core area for natural gas exploration and exploitation activities in western Canada. Capital expenditures for the nine months ended September 30, 2002, include the drilling of 150 net natural gas wells and 248 net oil wells.

North Sea capital expenditures for the three months ended September 30, 2002, include the consolidation of interests in the Ninian, Murchison, Lyell and Columba fields. The Company also acquired an interest in the Strathspey field, 12 licences covering 20 exploration blocks and part blocks, and additional equity interests in the Brent and Ninian pipelines and the Sullom Voe Terminal. The acquisition consideration includes a cash payment of US $120.0 million and the Company’s 5% interest in the Harding field. Capital expenditures for the nine months ended September 30, 2002, also include the consolidation of the Company’s ownership interests in the Ninian, Banff and Kyle fields in exchange for its interests in the Pierce and Claymore fields and cash. North Sea capital expenditures also include the drilling of wells at the Kyle and Columba E fields, as well as the ongoing infill drilling program in the Ninian field.

Offshore West Africa capital expenditures include the continued development of the Espoir field. During the third quarter 2002, a third producer well was completed in mid-July. The Company plans to drill two additional wells as part of the first development phase in the fourth quarter of 2002. In the third quarter 2002, the Company also entered into a production sharing agreement ("PSA") for Block 16, offshore Angola. The Company will operate the block and retain a 50% working interest. The PSA was effective September 1, 2002 for an initial four-year exploration phase.

	SEP 30 2002	JUN 30 2002	DEC 31 2001[1]	SEP 30 2001[1]
LIQUIDITY AND CAPITAL RESOURCES *($ millions, except ratios)*				
Working capital deficit	**$ 364.4**	$ 128.9	$ 5.6	$ 154.1
Long-term debt	**4,169.6**	2,404.4	2,669.2	2,311.8
Total	**$ 4,534.0**	$ 2,533.3	$ 2,674.8	$ 2,465.9
Shareholders' equity				
Preferred securities	**$ 126.9**	$ 121.5	$ 127.4	$ 126.3
Share capital	**2,289.0**	1,756.2	1,698.3	1,693.9
Retained earnings	**2,222.7**	2,122.0	1,908.5	1,867.6
Foreign currency translation adjustment	**22.7**	30.3	72.8	-
Total	**$ 4,661.3**	$ 4,030.0	$ 3,807.0	$ 3,687.8
Debt to cash flow[2]	**2.3x**	1.5x	1.4x	1.1x
Debt to book capitalization	**47.2%**	37.4%	41.2%	38.5%
Debt to market capitalization	**37.9%**	27.1%	34.9%	32.4%
After tax return on average common shareholders' equity[2]	**10.6%**	10.3%	18.7%	24.9%
After tax return on average capital employed[2]	**7.3%**	7.2%	12.2%	15.5%

(1) *Restated for change in accounting policy (see consolidated financial statements note 2).*
(2) *Based on trailing 12-month period and do not include amounts related to acquired assets for the 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 September 30, 2002, would be 2.4x (June 30, 2002 – 1.6x, December 31, 2001 – 1.5x, September 30, 2001 – 1.1x). Debt to book capitalization would be 48.7% at September 30, 2002 (June 30, 2002 – 39.3%, December 31, 2001 – 43.2%, September 30, 2001 – 40.6%) had the preferred securities been classified as long-term debt, while debt to market capitalization would be 39.0%, 28.5%, 36.6% and 34.2%, respectively.

SENSITIVITY ANALYSIS [1]

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

	Cash flow from operations[2] ($ millions)	Cash flow from operations[2] (per share) (basic)	Net earnings[2] ($ millions)	Net earnings[2] (per share) (basic)
Price changes				
Oil – WTI US $1.00/bbl[3]				
Excluding financial derivatives	$108	$0.81	$80	$0.60
Including financial derivatives	$49-$52	$0.36-$0.39	$36-$39	$0.27-$0.29
Natural gas – AECO Cdn $0.10/mcf[3]				
Excluding financial derivatives	$40	$0.30	$24	$0.18
Including financial derivatives	$35	$0.26	$22	$0.16
Volume changes				
Oil – 10,000 bbls/d	$60	$0.45	$14	$0.10
Natural gas – 10 mmcf/d	$7	$0.05	$1	$0.01
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $[3]				
Excluding financial derivatives	$58	$0.43	$36	$0.27
Including financial derivatives	$50-$55	$0.38-$0.41	$31-$34	$0.23-$0.25
Interest rate change – 1%	$22	$0.17	$14	$0.10

[1] *The sensitivities are calculated based on 2002 third quarter results.*
[2] *Attributable to common shareholders.*
[3] *For details of financial instruments in place, see consolidated financial statement note 8.*

OTHER OPERATING HIGHLIGHTS

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEP 30 2002	**JUN 30 2002**	**SEP 30 2001[(1)]**	**SEP 30 2002**	**SEP 30 2001[(1)]**
NETBACK ANALYSIS *($/boe, except daily production)*					
Daily production *(boe/d)*	**479,949**	369,022	361,029	**404,745**	356,905
Sales price	**$ 26.26**	$ 25.29	$ 24.25	**$ 24.57**	$ 29.76
Royalties	**3.80**	3.79	3.14	**3.49**	5.10
Production expense	**6.01**	5.76	5.47	**5.85**	5.75
Netback	**16.45**	15.74	15.64	**15.23**	18.91
Midstream contribution	**(0.23)**	(0.30)	(0.11)	**(0.25)**	(0.15)
Administration	**0.40**	0.37	0.28	**0.39**	0.26
Interest	**1.11**	0.85	0.97	**0.96**	1.09
Realized foreign exchange (gain) loss	**(0.04)**	0.03	0.02	**0.01**	0.02
Taxes other than income tax (current)	**0.29**	0.35	0.64	**0.35**	0.61
Current income tax (North Sea)	**0.07**	0.07	0.49	**0.15**	0.53
Current income tax (Offshore West Africa)	**0.08**	0.03	-	**0.05**	-
Current income tax (Large Corporations Tax)	**0.13**	0.14	0.10	**0.13**	0.11
Cash flow	**$ 14.64**	$ 14.20	$ 13.25	**$ 13.44**	$ 16.44

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

	NINE MONTHS ENDED SEPTEMBER 30, 2002			
	North America	**North Sea**	**Offshore West Africa**	**Total**
SEGMENTED NETBACK				
Oil and liquids *($/bbl, except daily production)*				
Daily production *(bbls/d)*	**165,608**	**34,629**	**6,585**	**206,822**
Sales price	**$ 26.85**	**$ 38.77**	**$ 38.95**	**$ 29.23**
Royalties	**3.28**	**2.06**	**1.36**	**3.01**
Production expense	**6.50**	**15.25**	**13.60**	**8.19**
Netback[(1)]	**$ 17.07**	**$ 21.46**	**$ 23.99**	**$ 18.03**
Natural gas *($/mcf, except daily production)*				
Daily production *(mmcf/d)*	**1,162**	**25**	**1**	**1,188**
Sales price	**$ 3.29**	**$ 2.56**	**$ 4.97**	**$ 3.28**
Royalties	**0.68**	**-**	**0.15**	**0.67**
Production expense	**0.54**	**1.65**	**1.77**	**0.57**
Netback[(1)]	**$ 2.07**	**$ 0.91**	**$ 3.05**	**$ 2.04**
Barrels of oil equivalent *($/boe, except daily production)*				
Daily production *(boe/d)*	**359,161**	**38,846**	**6,738**	**404,745**
Sales price	**$ 23.05**	**$ 36.27**	**$ 38.74**	**$ 24.57**
Royalties	**3.71**	**1.83**	**1.34**	**3.49**
Production expense	**4.76**	**14.67**	**13.54**	**5.85**
Netback[(1)]	**$ 14.58**	**$ 19.77**	**$ 23.86**	**$ 15.23**

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

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

	SEPTEMBER 30 2002	DECEMBER 31 2001
ASSETS		
Current assets		
Cash	**$ 15.2**	$ 15.0
Accounts receivable and other	**659.6**	509.0
	674.8	524.0
Property, plant and equipment *(net)*	**12,481.5**	8,442.9
Deferred charges *(note 4)*	**58.3**	-
	$ 13,214.6	$ 8,966.9
LIABILITIES		
Current liabilities		
Accounts payable	**$ 354.1**	$ 249.5
Accrued liabilities	**659.2**	264.2
Current portion of long-term debt *(note 5)*	**25.9**	15.9
	1,039.2	529.6
Long-term debt *(note 5)*	**4,169.6**	2,669.2
Future site restoration	**365.5**	193.8
Future income tax	**2,979.0**	1,767.3
	8,553.3	5,159.9
SHAREHOLDERS' EQUITY		
Preferred securities *(note 2)*	**126.9**	127.4
Share capital *(note 6)*	**2,289.0**	1,698.3
Retained earnings	**2,222.7**	1,908.5
Foreign currency translation adjustment	**22.7**	72.8
	4,661.3	3,807.0
	$ 13,214.6	$ 8,966.9

CONSOLIDATED STATEMENTS OF EARNINGS *(millions of Canadian dollars, except per share amounts) (unaudited)*

	THREE MONTHS ENDED SEPTEMBER 30		NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**	**2002**	**2001**
Revenue *(note 10)*	**$ 1,172.6**	$ 810.5	**$ 2,752.9**	$ 2,922.4
Less: royalties	**(167.7)**	(104.2)	**(386.0)**	(497.1)
	1,004.9	706.3	**2,366.9**	2,425.3
Expenses				
Production	**268.4**	183.1	**656.2**	568.5
Depletion, depreciation and amortization	**403.0**	236.2	**928.1**	661.4
Administration	**17.8**	9.4	**43.6**	25.6
Interest	**48.9**	32.2	**106.2**	106.4
Foreign exchange loss (gain) *(note 2)*	**40.2**	57.3	**(33.2)**	62.4
	778.3	518.2	**1,700.9**	1,424.3
Earnings Before Taxes	**226.6**	188.1	**666.0**	1,001.0
Taxes other than income tax	**13.6**	19.8	**41.9**	58.0
Current income tax	**12.3**	19.7	**36.0**	61.9
Future income tax	**76.4**	61.0	**222.6**	280.7
Net Earnings	**124.3**	87.6	**365.5**	600.4
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.4)	**(4.5)**	(4.3)
Revaluation of preferred securities *(note 2)*	**(5.4)**	(4.9)	**0.5**	(6.4)
Net Earnings Attributable to Common Shareholders	**$ 117.4**	$ 81.3	**$ 361.5**	$ 589.7
Net Earnings per Common Share Attributable to Common Shareholders *(note 7)*				
Basic	**$ 0.88**	$ 0.67	**$ 2.87**	$ 4.86
Diluted	**$ 0.86**	$ 0.66	**$ 2.78**	$ 4.72

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS *(millions of Canadian dollars) (unaudited)*

	NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**
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	**365.5**	600.4
Dividend on common shares *(note 6)*	**(47.3)**	(36.5)
Dividend on preferred securities *(net of tax)*	**(4.5)**	(4.3)
Revaluation of preferred securities *(note 2)*	**0.5**	(6.4)
Purchase of common shares *(note 6)*	**-**	(76.2)
Balance – End of Period	**$ 2,222.7**	$ 1,867.6

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

	THREE MONTHS ENDED SEPTEMBER 30		NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**	**2002**	**2001**
Operating Activities				
Net earnings	**$ 124.3**	$ 87.6	**$ 365.5**	$ 600.4
Non-cash items				
Depletion, depreciation and amortization	**403.0**	236.2	**928.1**	661.4
Deferred petroleum revenue tax	**0.6**	(1.3)	**3.6**	(1.2)
Future income tax	**76.4**	61.0	**222.6**	280.7
Unrealized foreign exchange loss (gain)	**42.1**	56.5	**(34.6)**	60.7
Cash flow provided from operations	**646.4**	440.0	**1,485.2**	1,602.0
Deferred charges	**(58.3)**	-	**(58.3)**	-
Net change in non-cash working capital	**(34.1)**	16.7	**(46.3)**	(9.6)
	554.0	456.7	**1,380.6**	1,592.4
Financing Activities				
Repay bank credit facilities	**(326.7)**	(709.8)	**(1,149.2)**	(792.9)
Issue of US debt securities	**1,107.8**	615.2	**1,749.3**	615.2
Repay senior unsecured notes	**(15.9)**	-	**(15.9)**	-
Repay lease obligations	**(1.9)**	-	**(1.9)**	-
Repay limited recourse loan	**-**	-	**-**	(11.8)
Issue of capital stock	**10.4**	16.0	**69.3**	38.3
Purchase of common shares	**-**	(18.7)	**-**	(113.3)
Dividend on common shares	**(15.4)**	(12.1)	**(42.8)**	(24.3)
Dividend on preferred securities	**(2.6)**	(2.6)	**(7.8)**	(7.7)
Net change in non-cash working capital	**(17.4)**	8.3	**(17.6)**	7.5
	738.3	(103.7)	**583.4**	(289.0)
Investing Activities				
Acquisition of Rio Alto, net of cash acquired *(note 3)*	**(843.2)**	-	**(843.2)**	-
Expenditures on property, plant and equipment	**(635.7)**	(354.0)	**(1,457.4)**	(1,369.2)
Net proceeds on sale of property, plant and equipment	**14.9**	1.9	**73.0**	14.4
Net expenditures on property, plant and equipment	**(1,464.0)**	(352.1)	**(2,227.6)**	(1,354.8)
Investment in Rio Alto International Inc.	**(15.7)**	-	**(15.7)**	-
Net change in non-cash working capital	**201.4**	2.1	**279.5**	58.4
	(1,278.3)	(350.0)	**(1,963.8)**	(1,296.4)
Increase in Cash	**14.0**	3.0	**0.2**	7.0
Cash – Beginning of Period	**1.2**	32.0	**15.0**	28.0
Cash – End of Period	**$ 15.2**	$ 35.0	**$ 15.2**	$ 35.0

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 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 a portion of its 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 portion of the US dollar denominated debt are included in the foreign currency translation adjustment in shareholders’ equity in the consolidated balance sheets. The effect of this hedge was to reduce foreign exchange losses and decrease the foreign currency translation adjustment by $41.7 million for the three months ended September 30, 2002.

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 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 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		NINE MONTHS ENDED		YEAR ENDED
	SEP 30 2002	**SEP 30 2001**	**SEP 30 2002**	**SEP 30 2001**	**DEC 31 2001**
Decrease deferred foreign exchange loss	**$ -**	$ (63.9)	**$ -**	$ (63.9)	$ (61.9)
Increase (decrease) preferred securities	**$ 5.4**	$ 8.1	**$ (0.5)**	$ 8.1	$ 9.1
Increase (decrease) opening retained earnings	**$ 12.1**	$ (20.9)	**$ (71.0)**	$ (15.4)	$ (15.4)
Foreign exchange loss (gain)	**$ 69.7**	$ 46.1	**$ (7.5)**	$ 50.1	$ 48.1
Revaluation of preferred securities	**$ 5.4**	$ 4.9	**$ (0.5)**	$ 6.4	$ 7.4

3. ACQUISITION OF RIO ALTO EXPLORATION LTD.

Effective July 1, 2002, the Company paid cash of $850.0 million and issued 10,008,000 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, Rio Alto's 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.

The acquisition of Rio Alto has strengthened the Company's exposure to natural gas production in western Canada and will provide additional cash flow to fund future capital projects.

The acquisition was accounted for based on the purchase method. Results from Rio Alto are consolidated with the results of the Company effective July 1, 2002. The preliminary estimate of 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:	
Share consideration	$ 522.4
Cash consideration	850.0
Total consideration	1,372.4
Long-term debt assumed	936.3
Total purchase price	$ 2,308.7
Net assets acquired:	
Property, plant and equipment	$ 3,383.9
Future income tax	(975.1)
Future site restoration	(35.9)
Cash	6.8
Non-cash working capital	(71.0)
Total net assets acquired	$ 2,308.7

The purchase price allocation is based on preliminary estimates of the fair values of the assets acquired, the liabilities assumed and the costs to complete the acquisition. The preliminary allocation is subject to change as actual amounts are determined.

4. DEFERRED CHARGES

The deferred charges relate to settlement payments made to terminate long-term natural gas contracts and financial contracts. The deferred charges are recognized against revenue over the original term of the contracts.

5. LONG-TERM DEBT

		SEPTEMBER 30 2002		DECEMBER 31 2001
Bank credit facilities				
Canadian dollar debt	**$**	**891.2**	$	1,003.4
US dollar debt *(2002 – US $100 million, 2001 – US $296 million)*		**158.6**		471.4
Medium-term notes		**250.0**		250.0
US debt securities *(2002 – US $1,500 million, 2001 – US $400 million)*		**2,378.7**		637.0
Senior unsecured notes *(2002 – US $318 million, 2001 – US $203 million)*		**499.8**		323.3
Obligations under capital leases		**17.2**		-
		4,195.5		2,685.1
Current portion of long-term debt		**(25.9)**		(15.9)
	$	**4,169.6**	$	2,669.2

Bank credit facilities

At September 30, 2002, the Company had unsecured bank credit facilities of approximately $3,100 million comprised of a $100 million operating demand facility, a revolving credit and term loan facility of $1,500 million, a revolving credit and term loan facility of US $150 million, a $500 million acquisition term credit facility repayable July 3, 2004 and a $725 million revolving credit and term loan facility. The $725 million credit and term loan facility was repaid and cancelled in October 2002.

At September 30, 2002, in conjunction with certain borrowings under its credit agreements, the Company irrevocably placed $140 million in escrow to be used solely for the repayment of those borrowings. This transaction was recognized as an in-substance defeasance and the debt was considered to be extinguished as at September 30, 2002.

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 $31.3 million have been issued.

US debt securities

On January 23, 2002, the Company issued US $400 million of US debt securities, maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the notes 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 August 16, 2002, the Company filed a short form shelf prospectus allowing for the issue of debt securities up to an aggregate principal amount of US $1 billion. On September 16, 2002, the Company issued US $350 million of US debt securities maturing October 1, 2012, bearing interest at 5.45% and US $350 million of US debt securities maturing June 30, 2033, bearing interest at 6.45%. Proceeds from the notes issued were used to repay bankers' acceptances under the Company's bank credit facilities.

Senior unsecured notes

On July 1, 2002, the Company assumed US $125 million of senior 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).

Obligations under capital leases

The obligations under capital leases bear interest at an average interest rate of 6.90% and are secured by the related assets.

6. SHARE CAPITAL

Issued

	SEPTEMBER 30, 2002		
	Number of shares *(thousands)*		**Amount**
Common shares			
Balance – January 1, 2002	**121,201**	**$**	**1,698.3**
Issued to acquire Rio Alto	**10,008**		**522.4**
Exercise of stock options	**2,083**		**67.0**
Issue of flow-through shares *(net of tax)*	**60**		**1.3**
Balance – September 30, 2002	**133,352**	**$**	**2,289.0**

On July 1, 2002, the Company issued 10,008,000 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 on The Toronto Stock Exchange on the day prior to the allotment of the common shares.

Normal course issuer bid

On January 17, 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 common shares outstanding 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 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 common shares outstanding on the date of announcement, during the 12-month period beginning January 23, 2002 and ending January 22, 2003. As at September 30, 2002, no common shares had been purchased under the renewed Normal Course Issuer Bid.

Dividend policy

On January 17, 2001, the Company announced a dividend policy to pay regular quarterly dividends 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.

Stock options

	SEPTEMBER 30, 2002		
	Stock options *(thousands)*		**Weighted average exercise price**
Outstanding – January 1, 2002	**12,051**	**$**	**34.77**
Granted	**3,174**		**41.88**
Exercised	**(2,083)**		**32.15**
Forfeited	**(353)**		**38.77**
Outstanding – September 30, 2002	**12,789**	**$**	**36.85**
Exercisable – September 30, 2002	**3,683**	**$**	**32.60**

Stock-based compensation costs

	THREE MONTHS ENDED SEPTEMBER 30		NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**	**2002**	**2001**
Stock-based compensation costs	**$ 6.6**	$ 4.9	**$ 18.1**	$ 13.7
Net earnings attributable to common shareholders				
As reported	**$ 117.4**	$ 81.3	**$ 361.5**	$ 589.7
Pro forma	**$ 110.8**	$ 76.4	**$ 343.4**	$ 576.0
Net earnings per common share attributable to common shareholders				
Basic				
As reported	**$ 0.88**	$ 0.67	**$ 2.87**	$ 4.86
Pro forma	**$ 0.83**	$ 0.63	**$ 2.73**	$ 4.75
Diluted				
As reported	**$ 0.86**	$ 0.66	**$ 2.78**	$ 4.72
Pro forma	**$ 0.81**	$ 0.62	**$ 2.64**	$ 4.62

The pro forma amounts shown above do not include the compensation costs associated with stock options granted prior to January 1, 2000.

	THREE MONTHS ENDED SEPTEMBER 30		NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**	**2002**	**2001**
Fair value of options granted *(per common share)*				
Directors, officers and executives	**$ -**	$ -	**$ 14.70**	$ 16.52
Other employees	**$ 13.17**	$ 13.72	**$ 12.36**	$ 13.69
Risk-free interest rate	**3.3%**	5.3%	**3.7%**	5.2%
Expected life *(years)*				
Directors, officers and executives	**-**	-	**5.5**	5.5
Other employees	**3.6**	3.6	**3.6**	3.6
Expected volatility	**35%**	34%	**37%**	39%
Expected dividend yield	**1.1%**	0.9%	**1.2%**	1.0%

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

	THREE MONTHS ENDED SEPTEMBER 30		NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**	**2002**	**2001**
Weighted average common shares outstanding *(thousands)*				
Basic	**133,201**	120,815	**125,950**	121,349
Effect of dilutive stock options	**3,507**	2,638	**3,095**	2,979
Assumed settlement of preferred securities with common shares[1]	**-**	-	**2,609**	2,759
Diluted	**136,708**	123,453	**131,654**	127,087
Net earnings attributable to common shareholders	**$ 117.4**	$ 81.3	**$ 361.5**	$ 589.7
Dividend on preferred securities[1]	**-**	-	**4.5**	4.3
Revaluation of preferred securities[1]	**-**	-	**(0.5)**	6.4
Diluted net earnings attributable to common shareholders	**$ 117.4**	$ 81.3	**$ 365.5**	$ 600.4
Net earnings per common share attributable to common shareholders				
Basic	**$ 0.88**	$ 0.67	**$ 2.87**	$ 4.86
Diluted	**$ 0.86**	$ 0.66	**$ 2.78**	$ 4.72
Cash flow from operations attributable to common shareholders	**$ 643.8**	$ 437.4	**$ 1,477.4**	$ 1,594.3
Dividend on preferred securities[1]	**-**	-	**7.8**	7.7
Diluted cash flow from operations attributable to common shareholders	**$ 643.8**	$ 437.4	**$ 1,485.2**	$ 1,602.0
Cash flow from operations per common share attributable to common shareholders				
Basic	**$ 4.83**	$ 3.62	**$ 11.73**	$ 13.14
Diluted	**$ 4.71**	$ 3.54	**$ 11.28**	$ 12.61

[1] *Preferred securities are anti-dilutive for the three months ended September 30, 2002 and September 30, 2001, but are dilutive for the nine months ended September 30, 2002 and September 30, 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 Company has the following financial derivatives outstanding as at the date hereof:

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps				
	Oct. 2002 – Dec. 2002	20,000 bbls/d	US $1.28	Dated Brent/WTI
	Jan. 2003 – Dec. 2003	15,000 bbls/d	US $1.00	Dated Brent/WTI
Oil price collars				
	Oct. 2002 – Dec. 2002	153,500 bbls/d	US $21.92 – US $26.94	WTI
	Jan. 2003 – Jun. 2003	104,000 bbls/d	US $22.09 – US $27.26	WTI
	Jul. 2003 – Aug. 2003	60,000 bbls/d	US $23.00 – US $27.85	WTI
Oil price fixed				
	Oct. 2002 – Dec. 2002	7,000 bbls/d	US $22.13	WTI

	Remaining Term	Volume	Average Price	Index
Natural Gas				
NYMEX fixed				
	Oct. 2002	90,000 mmbtu/d	US $2.85	NYMEX
	Nov. 2002 – Dec. 2002	30,000 mmbtu/d	US $3.27	NYMEX
NYMEX collar				
	Nov. 2002 – Oct. 2003	30,000 mmbtu/d	US $2.88 – US $6.12	NYMEX
Sumas fixed				
	Oct. 2002 – Oct. 2003	10,000 mmbtu/d	Cdn $2.85	Sumas
AECO collars				
	Oct. 2002 – Dec. 2002	100,000 GJ/d	Cdn $4.25 – Cdn $6.03	AECO
	Nov. 2002 – Mar. 2003	30,000 GJ/d	Cdn $4.00 – Cdn $8.43	AECO
	Nov. 2002 – Oct. 2003	40,000 GJ/d	Cdn $3.50 – Cdn $5.38	AECO
AECO fixed				
	Oct. 2002	5,000 GJ/d	Cdn $2.71	AECO

	Remaining Term	Amount *($ millions)*	Average Exchange Rate *(US $/Cdn $)*
Foreign Currency			
Currency fixed	Oct. 2002	US $0.4/month	1.37
Currency collars	Oct. 2002 – May 2003	US $4.2/month	1.43 – 1.53
	Oct. 2002 – 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	Oct. 2002 – Dec. 2005	US $125	1.55	7.69%	7.30%

	Remaining Term	Amount *($ millions)*	Fixed Rate	Floating Rate
Interest Rate				
Swaps – fixed to floating	Oct. 2002 – Jul. 2004	US $200	6.70%	LIBOR + 2.09%
	Oct. 2002 – Jul. 2006	US $200	6.70%	LIBOR + 1.58%
	Oct. 2002 – Jan. 2005	US $200	7.20%	LIBOR + 3.00%
	Oct. 2002 – Jan. 2007	US $200	7.20%	LIBOR + 2.23%
Swap – floating to fixed	Oct. 2002 – Mar. 2004	Cdn $100	5.08%	

9. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	THREE MONTHS ENDED SEPTEMBER 30		NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**	**2002**	**2001**
Interest paid	**$ 56.5**	$ 25.8	**$ 103.8**	$ 99.0
Taxes paid	**$ 28.9**	$ 37.8	**$ 92.5**	$ 118.5

10. SEGMENTED INFORMATION

	THREE MONTHS ENDED SEPTEMBER 30		NINE MONTHS ENDED SEPTEMBER 30	
	2002	**2001**	**2002**	**2001**
Revenue				
North America	**$ 936.6**	$ 651.6	**$ 2,259.7**	$ 2,456.3
North Sea	**186.2**	141.7	**384.7**	407.8
Offshore West Africa	**36.5**	12.2	**71.3**	35.8
Midstream	**13.3**	5.0	**37.2**	22.5
	$ 1,172.6	$ 810.5	**$ 2,752.9**	$ 2,922.4
Net Earnings				
North America	**$ 112.9**	$ 74.8	**$ 387.8**	$ 503.5
North Sea	**(0.1)**	15.6	**(20.1)**	94.9
Offshore West Africa	**6.7**	(4.4)	**(14.8)**	(4.6)
Midstream	**4.8**	1.6	**12.6**	6.6
	124.3	87.6	**365.5**	600.4
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.4)	**(4.5)**	(4.3)
Revaluation of preferred securities	**(5.4)**	(4.9)	**0.5**	(6.4)
Net Earnings Attributable to Common Shareholders	**$ 117.4**	$ 81.3	**$ 361.5**	$ 589.7
Additions to Property, Plant and Equipment (excluding Acquisition of Rio Alto)				
North America	**$ 331.8**	$ 280.9	**$ 984.4**	$ 1,164.8
North Sea	**295.6**	32.2	**251.4**	63.5
Offshore West Africa	**58.7**	22.9	**173.1**	160.8
Midstream	**-**	16.1	**14.8**	51.8
	$ 686.1	$ 352.1	**$ 1,423.7**	$ 1,440.9

Property, plant and equipment and future income taxes payable have been increased by $39.3 million (2001 increased by $86.1 million) to provide for the tax effect of the sale and acquisition of assets in the North Sea and North America with a tax basis that differs from the purchase and sale price.

	PROPERTY, PLANT AND EQUIPMENT		TOTAL ASSETS	
	SEPTEMBER 30 2002	**DECEMBER 31 2001**	**SEPTEMBER 30 2002**	**DECEMBER 31 2001**
Segmented Assets				
North America	**$ 10,644.8**	$ 6,984.0	**$ 11,256.4**	$ 7,392.5
North Sea	**1,140.5**	866.2	**1,219.2**	941.6
Offshore West Africa	**508.3**	409.9	**534.6**	433.2
Midstream	**187.9**	182.8	**204.4**	199.6
	$ 12,481.5	$ 8,442.9	**$ 13,214.6**	$ 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 12-month period ended September 30, 2002:	
Interest coverage *(times)*	
Net earnings	6.1[1]
Cash flow from operations attributable to common shareholders	14.5[2]

[1] *Net earnings plus income taxes and interest expense; divided by interest expense.*

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

The interest coverage ratios have been calculated without including the annual carrying charges relating to the outstanding preferred securities of the Company. If the preferred securities were classified as long-term debt, these annual carrying charges would be included in interest. If these annual carrying charges had been included in the calculations, the net earnings coverage ratio for the 12-month period ended September 30, 2002, would be 5.6x and the cash flow coverage ratio for the 12-month period ended September 30, 2002 would be 13.5x.

2002 YEAR END RESULTS

2002 year end results are scheduled for release Wednesday, February 26, 2003. A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time.

CORPORATE PROFILE

Canadian Natural Resources Limited is a senior independent oil and natural gas exploration, development and production company based in Calgary, Alberta. The Company's operations are focused in Western Canada, the North Sea and Offshore West Africa.

Canadian Natural's profitable growth has been based on the fundamental principles of effective cost control, manageable bank debt and a defined operating strategy. The strategy follows a balanced approach to exploration and acquisitions, combined with a focus on cost effective exploitation in defined core areas. Adhering to this strategy has resulted in Canadian Natural building a strong asset base that is diversified among commodities produced, namely natural gas, light and Pelican Lake oil, primary heavy oil and thermal heavy oil.

CORPORATE INFORMATION

Management Committee

Allan P. Markin
Chairman

John G. Langille
President

Brian L. Illing
Executive Vice-President, Exploration

Steve W. Laut
Executive Vice-President, Operations

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

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

Réal M. Cusson
Vice-President, Marketing

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

Douglas A. Proll
Vice-President, Finance

Lyle G. Stevens
Vice-President, Exploitation

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Board of Directors

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Ambassador Gordon D. Giffin

James T. Grenon

John G. Langille

Keith A.J. MacPhail

Allan P. Markin

James S. Palmer, C.M., Q.C.

Eldon R. Smith, M.D.

David A. Tuer

Stock Listing

The Toronto Stock Exchange
Symbol: CNQ
New York Stock Exchange
Symbol: CED

Investor Relations

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Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

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Trading Symbols
The Toronto Stock Exchange – CNQ   New York Stock Exchange – CED

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