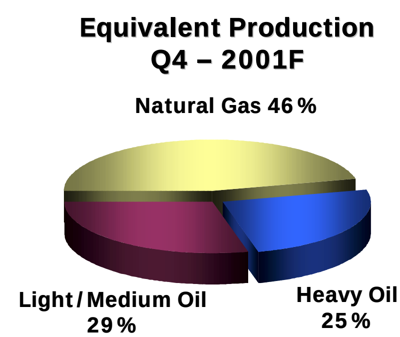
CANADIAN NATURAL RESOURCES LIMITED

Press Release

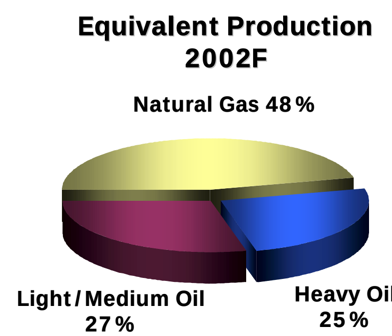
CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2001 THIRD QUARTER RESULTS
CALGARY, ALBERTA – NOVEMBER 7, 2001 – FOR IMMEDIATE RELEASE

CANADIAN NATURAL ANNOUNCES STRONG THIRD QUARTER AND FIRST NINE MONTH 2001 RESULTS; CURRENT NATURAL GAS PRODUCTION IN EXCESS OF 1 BCF/DAY

In commenting on third quarter results, Chairman Allan Markin stated "Canadian Natural's ongoing drilling and acquisition activities have resulted in increased balance among different products. Our natural gas production is now in excess of 1 bcf per day, or 46% of product mix, and we expect natural gas production will comprise 48% of 2002 average production. Light and medium oils represent about 29% of our product mix with heavy oil now accounting for 25% of production."



"A recap of the acquisition portion of our 2001 capital program shows the Company's continuing adherence to our defined business strategy of controlling our assets in the core areas in which we operate. In January, we bought additional interests contiguous to our Pelican Lake medium oil play. In June, we acquired additional interests in our Espoir Côte d'Ivoire light oil play. Over the last two months we have acquired additional Canadian natural gas assets which consolidates our position in the Helmet gas play of northeast British Columbia and we were appointed Technical Advisor with the largest participating interest in the Aje field light oil discovery in our offshore West Africa core area."



"Complimenting this acquisition program has been our ongoing exploration and development program which has resulted in significant discoveries of oil and natural gas. The most prolific discovery has been at Ladyfern in British Columbia where we have now drilled five excellent natural gas wells. Current production from the two tied-in wells is 100 million cubic feet per day. Production will continue to grow to 200 million cubic feet per day with the completion of additional production and pipeline facilities."

"As a result of the recently completed acquisitions, our 2001 capital expenditures will amount to approximately $1.9 billion. A shift of drilling emphasis has also provided for internal production growth. In January, we altered our drilling program away from liquids and into natural gas. Our 2001 natural gas exit volumes will grow by over 30% from 2000 exit rates. We expect our 2001 daily production volumes to meet our targeted production level of over 360 thousand barrels of oil equivalent, with daily oil production averaging 207 to 210 thousand barrels and daily natural gas production averaging 920 to 930 million cubic feet."

HIGHLIGHTS OF THE THIRD QUARTER

- Year to date cash flow increased 20% to $1.6 billion ($13.14 per common share) from $1.3 billion ($11.58 per common share) in the first nine months of 2000. Third quarter cash flow was $437 million ($3.63 per common share).
- Earnings increased 16% to $646 million ($5.33 per common share) from $559 million ($4.86 per common share) in the first nine months of 2000. Third quarter earnings amount to $132 million ($1.10 per common share).
- Third quarter average natural gas sales were 924 million cubic feet per day (mmcf/d), an increase of 39 mmcf/d over second quarter production levels and 79 mmcf/d over prior year amounts.
- Third quarter oil and liquids sales of 207 thousand barrels per day.
- Netback per barrel of oil equivalent, a healthy $15.75 despite weakening North American natural gas pricing.

- A $0.21 reduction in operating costs per barrel of oil equivalent from the second quarter of 2001.
- A trailing twelve month 26% after tax return on average common shareholders' equity.
- Quarterly capital expenditures of $352 million were lower than cash flow of $437 million, with $297 million spent on North American properties and $55 million spent in the UK North Sea and other international areas.
- Completed testing and tie-in of Slave Point wells at Ladyfern, British Columbia with production currently at a facility restricted rate of 100 million cubic feet per day.
- Drilled, completed and tested a new zone in the third well at the Kyle field in the UK North Sea.
- Espoir development in Côte d'Ivoire continues on-time and on-budget with first oil sales expected during the first quarter of 2002. The construction of the FPSO for this project has been completed and the FPSO will sail to Côte d'Ivoire in November.
- Acquisition of the Canadian assets of a US based producer which results in 100% ownership of the Company's producing natural gas assets and undeveloped land in the Helmet area of northeastern British Columbia. The acquisition closed in the fourth quarter.
- Expansion of core areas in offshore West Africa through an agreement to participate and provide Technical Assistance in the development of known oil, condensate and natural gas reserves in the Aje field, located offshore Nigeria.
- Completed phase 1 of the front-end engineering work for development of oil sands leases in the Horizon Project.
- Completed agreements to dispose of substantially all of the US assets acquired with Ranger Oil for proceeds of Cdn $49 million. Disposition was closed in the fourth quarter.
- Completion of inaugural US debt borrowing of US $400 million of 10 year notes at an interest rate of 6.70%. Debt was subsequently swapped for a period of 3 to 5 years to floating rate debt. Our overall corporate average borrowing rate is currently under 5%.
- Repurchased 431,000 common shares under its Normal Course Issuer Bid. A total of 2,537,800 common shares repurchased to date.
- Paid third quarterly dividend of $0.10 per share.

OPERATIONS REVIEW

Production

The year to date results show the strength of the Company's business approach to diversification among commodities produced, namely natural gas, light and medium oil and heavy oil. Canadian Natural believes this diversification provides reduced price risk when compared with over leverage to one commodity.

Third quarter 2001 natural gas production averaged 924 mmcf/d, an increase of 39 mmcf/d from the second quarter of 2001 and 79 mmcf/d from the third quarter of 2000. During the third quarter, production from the Ladyfern pool in northeast British Columbia averaged a pipeline constrained 55 mmcf/d. On a barrel of oil equivalent (boe) basis, natural gas production accounted for 43% of the Company's third quarter production, up from 40% in the prior year. Natural gas continues to be Canadian Natural's largest product offering and in early October, Canadian Natural reached the 1 billion cubic feet per day level of natural gas production.

Oil and liquids production in the third quarter of 2001 decreased 4% from the second quarter of this year, reflecting the Company's decision in the first quarter to drill more natural gas locations, to reduce steaming at the Company's thermal oil properties due to high natural gas prices and to defer drilling and recompletion operations in certain of the Company's heavy oil properties. Production levels remained flat with the same period of the prior year. During the third quarter, light/medium oil production accounted for 31% of the Company's total production, consistent with 2000 levels. Light oil production increased due to the tie-in of the Canadian Natural operated Kyle field and the re-commencement of production from the Banff field. Both fields are located in the UK sector of the North Sea. Significantly higher netbacks are achieved from these fields as revenues are subject only to UK corporate tax with no encumbrance for royalties or petroleum revenue tax. Heavy oil production in the third quarter of 2001 represented 26% of company production.

The Company's production composition was as follows:

	Q3 2001 Mboe/d	%	Q2 2001 Mboe/d	%	Q3 2000 Mboe/d	%
Natural gas	**154.0**	**43**	147.5	41	140.7	41
Light and medium oil	**112.1**	**31**	114.7	32	111.7	32
Heavy oil	**94.9**	**26**	100.0	27	95.0	27
	361.0		362.2		347.4	

Canadian Natural drilled an additional 227 net wells during the quarter, with a focus on natural gas (173 net wells). The majority of these wells were located in the shallow gas region of southern Alberta. The total success rate for Canadian Natural's drilling program remained over 97% in the third quarter of the year.

As a result of the successful 2001 natural gas drilling program, Canadian Natural increased its 2001 average target level of natural gas production to a range of 920 to 930 million cubic feet per day from its original daily target of 825 to 850 million cubic feet. Re-allocation of capital from expenditures on heavy oil properties resulted in a reduction of 2001 average oil production to a range of 207 to 210 thousand barrels of oil per day. Total average production for 2001 will be in excess of 360 thousand barrels of oil equivalent per day, an 18% increase over 2000 production.

During the fourth quarter of 2001, the company expects to average in excess of 1 bcf/d of natural gas. The significant increase in natural gas production is primarily attributable to consolidation of property interest lands in the Helmet area as well as additional development drilling and facility construction at Ladyfern. Both of those areas are in the Company's core operating region of northeastern British Columbia. Based on the Company's projected 2002 capital budget of $1.5 billion, annual volumes in 2002 are expected to average 1,075 to 1,125 mmcf/d of natural gas and 200 to 210 thousand barrels of oil and liquids per day.

Pricing

Netbacks received for Canadian Natural's oil and liquids production improved in the third quarter of the year reflecting lower discounts on price from the WTI benchmark price, decreased blending condensate costs, and lower operating costs. In contrast, natural gas prices declined significantly during the third quarter from the levels achieved during the first half of 2001 and the third quarter of 2000. This decline is attributable to lower demand in the North American markets.

A comparison of the price received for the Company's natural gas and oil production is as follows:

	Q3 2001	Q2 2001	Q3 2000
WTI benchmark price (US $/bbl)	**$ 26.57**	$ 27.96	$ 31.55
Differential to LLB blend (US $/bbl)	**$ 8.10**	$ 11.70	$ 7.01
Condensate benchmark price (US $/bbl)	**$ 26.70**	$ 33.04	$ 31.43
Canadian Natural Wellhead Price			
Primary heavy oil ($/bbl)	**$ 23.69**	$ 16.74	$ 30.91
Thermal heavy oil ($/bbl)	**$ 22.46**	$ 14.53	$ 29.28
Pelican Lake medium oil ($/bbl)	**$ 24.99**	$ 18.80	$ 32.11
Natural gas ($/mcf)	**$ 3.12**	$ 5.93	$ 4.30

North America

At Ladyfern the Company's 2001 drilling program is being completed as planned. Based on 3-D seismic in the immediate Ladyfern area the Company identified 8 excellent drilling locations to be evaluated in 2001. The status of this program to date is as follows:

2 wells drilled, completed and producing
1 well drilled, completed and tested
2 wells drilled, being completed and tested
1 well drilling
2 wells to commence drilling prior to the end of 2001

By the end of the third quarter, Canadian Natural completed the drilling and tie-in of the Ladyfern c-82-G/94-H-1 and d-74-G/94-H-1 wells with pipeline restricted production averaging 55 mmcf/d during the quarter. In addition, the well at d-86-G/94-H-1 was drilled, completed and tested in October. Each of these wells is capable of production in excess of 100 mmcf/d.

Additional pipeline connections are being completed to tie into existing production facilities in British Columbia. Due to surface access delays in this work, current production is at 100 mmcf/d versus the 140 mmcf/d anticipated in August. All five wells drilled to date will be fully tested and tied-in by the end of November, 2001. Canadian Natural believes that Ladyfern production may increase to approximately 200 mmcf/d in December 2001. Additional volumes will be added in 2002, with increased pipeline takeaway capacity into Alberta expected by April 2002.

The results of wells drilled to date in the Ladyfern area confirm the anomalies identified on seismic. Extensive 2-D and 3-D seismic has been shot and processed over portions of Canadian Natural's land and the Company has identified additional locations with geophysical characteristics similar to the wells drilled to date. Canadian Natural owns a 100% interest in its Ladyfern wells and an additional 30,000 acres of undeveloped land in the area. Plans for 2002 include the drilling of up to 12 additional wells to test Slave Point anomalies identified on the seismic.

At its thermal oil operations at Primrose, Alberta, Canadian Natural received requlatory approval in the third quarter to convert a further three low pressure cyclic pads to high pressure cyclic pads. This is in addition to the two pads which were previously approved for conversion in 2000. With these approvals, Canadian Natural is better able to control steam injection volumes and timing. As a result, oil production from these high pressure pads will be produced in the second and third quarter of 2002.

Canadian Natural has also commenced a pilot project to determine the economic feasibility of burning produced heavy oil instead of natural gas to generate steam for its thermal operations. If this test is successful, additional conversion of heat generators would enable Canadian Natural to mitigate the effect of high natural gas prices on its production cost of thermal heavy oil.

Canadian Natural's Horizon oil sands project has completed the first phase of its front-end engineering work. The Company's approach for this project is to extensively evaluate new technology options and predesign the infrastructure prior to construction. In this way, Canadian Natural will ensure cost certainty before significant activity begins. A strong staff of experts in each of mining, extraction and upgrading has been assembled to lead this work. With respect to bitumen upgrading, Canadian Natural continues to evaluate various options, including both full and partial upgrading. Further applications for project approval with regulatory authorities will be submitted in mid 2002. Canadian Natural continues to anticipate start of construction in 2004 with first synthetic oil production as early as 2006.

At the time of acquiring Ranger Oil in the summer of 2000, Canadian Natural evaluated the properties owned by Ranger Oil in the United States and determined that those properties would not constitute an ongoing core region for the Company. Accordingly, substantially all of these properties were sold for Cdn $49 million plus an overriding royalty interest in certain properties. The transaction closed in October.

International

In Côte d'Ivoire, Canadian Natural continues the development of the Espoir field on-budget and on-schedule. The field is scheduled to produce in early 2002 at a rate of 12,700 barrels of oil per day and 34 million cubic feet of natural gas per day. Canadian Natural is operator of the field with a 59% working interest. The well head tower was installed in April and batch drilling of all seven development wells is now completed to the intermediate casing stage. Two wells have been drilled and logged in the reservoir section with results meeting Canadian Natural's expectations. The hydrocarbon processing will be carried out on a Floating Production Storage and Offtake vessel which is currently undergoing final seaworthiness testing in Singapore and will shortly embark to the field. A subsea pipeline has been constructed for the delivery of associated natural gas to onshore Côte d'Ivoire where it will be sold to local power producers.

In deeper water south of Espoir, Canadian Natural will be drilling an appraisal well and two exploration wells on nearby separate structures. A drilling rig has been contracted to commence this drilling in late December and into 2002. These two structures have the potential for significant quantities of light oil. Canadian Natural is operator and holds a 61% working interest in these projects.

Through its recent appointment as Technical Advisor for development of the Aje field in offshore Nigeria, the company has expanded its core area from Côte d'Ivoire along the Bénin Basin. Prior to Canadian Natural's appointment, two wells were drilled on this property, encountering multiple pay zones containing light oil and condensate. Further drilling in this field is scheduled to commence in late 2002.

ACTIVITY BY CORE REGION	Undeveloped Land As at September 30, 2001 (thousands of net acres)	Drilling Activity Nine months ended September 30, 2001 (net wells)
Northeastern British Columbia/Northwestern Alberta	**1,462**	**88**
North Central Alberta	**2,481**	**181**
Alberta Oil Sands	**236**	**197**
Eastern Alberta/Western Saskatchewan	**1,084**	**180**
South Central Alberta	**647**	**316**
Williston Basin	**301**	**4**
United Kingdom North Sea	**215**	**2**
Offshore West Africa	**1,258**	**1**

	NINE MONTHS ENDED SEPTEMBER 30			
	2001		2000	
DRILLING ACTIVITY	**Gross**	**Net**	**Gross**	**Net**
Oil	**264**	**228**	316	282
Natural gas	**541**	**460**	425	381
Injection/strat tests	**251**	**250**	30	26
Dry	**38**	**32**	27	25
Total	**1,094**	**970**	798	714
Success rate		**97%**		96%

FINANCIAL REVIEW

In July 2001, Canadian Natural filed shelf prospectuses in Canada and the United States for the separate offering of up to $1 billion of medium term notes in Canada and up to US $1 billion of debt securities in the United States. The securities, if and when issued, will be unsecured and will rank *pari passu* with other senior unsecured indebtedness of Canadian Natural. On July 24, 2001, the Company issued US $400 million of ten year, 6.70% notes to purchasers in the United States under the above shelf. Net proceeds from the sale were used 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 purpose for future offerings under the shelf prospectuses is to provide flexibility to the Company’s debt investment base, extend maturities and provide balance in fixed/floating interest rate ratios.

In the year to date, Canadian Natural has cancelled three bank lines of credit aggregating approximately $1 billion. The Company’s unutilized bank lines of credit currently exceed $400 million and are in addition to funds that are available through the Company’s Canadian and US shelf prospectuses. On an annualized basis, the Company’s debt to cash flow ratio is 1.1 times and the debt to book capitalization ratio is 40%.

In response to recent concerns over North American economic activity, the related demand for oil and natural gas and to protect our capital expenditure programs, we have entered into several financial derivative contracts to manage our exposure to market volatility. In summary, for the first half of 2002, we have utilized costless collars to underpin the price for approximately 30% of our oil production in a range averaging WTI US $20.00 to WTI US $24.60 and the price at AECO for approximately 20% of our natural gas production in a range averaging Cdn $3.50 to Cdn $4.40. The details of our hedge positions are set out in Note 6 to the Consolidated Financial Statements.

Our financial position is strong and we will continue to adhere to our long term targets ensuring our financial flexibility.

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, 2001 and the MD&A and audited consolidated financial statements for the year ended December 31, 2000.

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.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
FINANCIAL HIGHLIGHTS ($ millions, except per share amounts)					
Gross revenue	**$ 806**	$ 973	$ 1,004	**$ 2,900**	$ 2,192
Cash flow attributable to common shareholders [(1)]	**$ 437**	$ 528	$ 587	**$ 1,594**	$ 1,331
Per share – basic	**$ 3.63**	$ 4.36	$ 4.97	**$ 13.14**	$ 11.58
– diluted	**$ 3.50**	$ 4.18	$ 4.80	**$ 12.62**	$ 11.25
Net earnings attributable to common shareholders [(1)]	**$ 132**	$ 249	$ 241	**$ 646**	$ 559
Per share – basic	**$ 1.10**	$ 2.06	$ 2.04	**$ 5.33**	$ 4.86
– diluted	**$ 1.08**	$ 1.97	$ 1.97	**$ 5.13**	$ 4.73
Capital expenditures, net of dispositions	**$ 352**	$ 368	$ 222	**$ 1,355**	$ 941
Acquisition of Ranger Oil Limited	**$ -**	$ -	$ 1,687	**$ -**	$ 1,687

[(1)]After dividend on preferred securities

OPERATING HIGHLIGHTS

	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
Oil and liquids					
Daily production (bbls)	**207,065**	214,716	206,696	**209,128**	163,807
Sales price	**$ 28.37**	$ 25.32	$ 35.23	**$ 25.28**	$ 31.91
Royalties	**2.47**	2.42	3.36	**2.41**	3.14
Operating costs	**7.10**	7.32	6.97	**7.43**	5.87
Netback ($/bbl)	**$ 18.80**	$ 15.58	$ 24.90	**$ 15.44**	$ 22.90
Natural gas					
Daily production (mmcf)	**923.8**	884.6	844.5	**886.7**	781.8
Sales price	**$ 3.12**	$ 5.93	$ 4.30	**$ 6.01**	$ 3.55
Royalties	**0.67**	1.47	1.05	**1.49**	0.81
Operating costs	**0.50**	0.50	0.45	**0.50**	0.43
Netback ($/mcf)	**$ 1.95**	$ 3.96	$ 2.80	**$ 4.02**	$ 2.31
Barrel of oil equivalent (6:1)					
Daily production (boe)	**361,029**	362,154	347,447	**356,905**	294,107
Sales price	**$ 24.25**	$ 29.54	$ 31.40	**$ 29.76**	$ 27.20
Royalties	**3.14**	5.03	4.54	**5.10**	3.89
Operating costs	**5.36**	5.57	5.25	**5.60**	4.41
Netback ($/boe)	**$ 15.75**	$ 18.94	$ 21.61	**$ 19.06**	$ 18.90

Cash flow and net earnings for the nine months ended September 30, 2001, increased over the comparable period in 2000 due to higher year to date natural gas prices and increased production volumes. Third quarter 2001 cash flow and net earnings decreased from second quarter 2001 due mainly to the effects of weaker market prices for natural gas and lower oil and liquids production during the quarter.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
DAILY PRODUCTION					
Oil and liquids (bbls/day)					
North America	**162,890**	168,938	165,342	**169,261**	149,922
North Sea	**40,356**	41,556	37,686	**36,422**	12,653
Other International	**3,819**	4,222	3,668	**3,445**	1,232
Total	**207,065**	214,716	206,696	**209,128**	163,807
Natural gas (mmcf/day)					
North America	**905.7**	872.6	838.8	**876.6**	779.9
North Sea	**18.1**	12.0	5.7	**10.1**	1.9
Total	**923.8**	884.6	844.5	**886.7**	781.8

Production increased over the first nine months of 2000 due to the acquisition of Ranger Oil Limited (“Ranger”) completed in the third quarter of 2000. North America third quarter 2001 oil and liquids production decreased from second quarter 2001 due to the focus on natural gas drilling and a deferral of steam stimulation of thermal heavy oil production during the first half of the year. North America third quarter 2001 natural gas production increased from the second quarter 2001 due to the completion and tie-in of the first Ladyfern well in late June and the second well at Ladyfern in early August. Production from the Ladyfern field continues to be restricted by pipeline capacity.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
PRODUCT PRICES					
Oil and liquids ($/bbl)					
North America	**$ 26.02**	$ 20.59	$ 32.54	**$ 21.77**	$ 30.60
North Sea	**$ 37.28**	$ 43.07	$ 45.22	**$ 40.41**	$ 45.22
Other International	**$ 34.66**	$ 39.75	$ 54.05	**$ 38.03**	$ 54.05
Company average	**$ 28.37**	$ 25.32	$ 35.23	**$ 25.28**	$ 31.91
Natural gas ($/mcf)					
North America	**$ 3.13**	$ 5.99	$ 4.30	**$ 6.05**	$ 3.54
North Sea	**$ 2.51**	$ 1.74	$ 3.65	**$ 2.21**	$ 3.65
Company average	**$ 3.12**	$ 5.93	$ 4.30	**$ 6.01**	$ 3.55

North America realized oil price for the nine months ended September 30, 2001 decreased from the comparable period in 2000 primarily as a result of wider heavy oil differentials, averaging US $10.93 per barrel in the first nine months of 2001 compared to US $6.12 per barrel for first nine months of 2000. Oil market prices declined throughout the third quarter, but the Company’s realized oil price in the third quarter 2001 improved due to the narrowing of the heavy oil differential from

US $11.70 per barrel in the second quarter to US $8.10 per barrel and a reduction in the cost of condensate used to blend heavy oil. North American realized natural gas price increased in the first nine months of 2001 over the comparable period in 2000 due to a tighter supply environment in the first half of the year. Realized natural gas prices continued to decrease in the third quarter 2001 due to a decrease in market demand for natural gas.

Arrangements entered into by the Company to fix a portion of the price realized from the sale of oil reduced the price by $0.22 per barrel in the quarter ended September 30, 2001 ($0.43 and $1.98 reduction per barrel, respectively, in the quarters ended June 30, 2001 and September 30, 2000). The price realized from the sale of natural gas was reduced by $0.10 per mcf in the third quarter 2001 ($0.31 and $0.46 reduction per mcf, respectively, in the quarters ended June 30, 2001 and September 30, 2000).

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
ROYALTIES					
Oil and liquids ($/bbl)					
North America	**$ 2.61**	$ 2.51	$ 3.74	**$ 2.47**	$ 3.26
North Sea	**$ 1.97**	$ 2.23	$ 2.00	**$ 2.29**	$ 2.00
Other International	**$ 2.03**	$ 0.65	$ -	**$ 1.02**	$ -
Natural gas ($/mcf)					
North America	**$ 0.68**	$ 1.49	$ 1.05	**$ 1.50**	$ 0.81
Company average ($/boe)	**$ 3.14**	$ 5.03	$ 4.54	**$ 5.10**	$ 3.89

Oil and liquids royalties declined in North America for the first nine months of 2001 from the comparable period in 2000 due to lower prices and increased production of heavy and thermal heavy oil which qualifies for a lower royalty structure. Natural gas royalties increased from the first nine months of 2000 due to the overall increase in natural gas prices. In the third quarter of 2001, North America oil and liquids royalties have increased over second quarter 2001 due to higher realized prices as a result of the narrower heavy oil differential.

North Sea oil and liquids royalties per boe increased for the first nine months of 2001 because production from the Banff and Kyle non royalty paying fields did not recommence production until the second quarter of 2001. In the third quarter royalties decreased as a result of lower realized prices.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
PRODUCTION EXPENSES					
Oil and liquids ($/bbl)					
North America	**$ 6.57**	$ 6.80	$ 6.13	**$ 6.89**	$ 5.45
North Sea	**$ 8.09**	$ 8.42	$ 9.13	**$ 8.50**	$ 9.13
Other International	**$ 19.05**	$ 17.23	$ 22.75	**$ 22.61**	$ 22.75
Natural gas ($/mcf)					
North America	**$ 0.50**	$ 0.50	$ 0.45	**$ 0.50**	$ 0.43
North Sea	**$ 0.74**	$ 0.61	$ 0.84	**$ 0.69**	$ 0.84
Company average ($/boe)	**$ 5.36**	$ 5.57	$ 5.25	**$ 5.60**	$ 4.41

The increase in North America oil and natural gas production expenses from the first nine months of 2000 is attributable to higher associated costs for fuel, power and processing in the first half of the year. The cost of processing thermal heavy oil in Canada was also affected by the increased cost of natural gas used to produce steam to heat the oil formation. In the third quarter 2001, lower fuel and natural gas costs have resulted in reduced oil and liquids production expenses. North Sea production expenses per boe decreased from the second quarter and prior year primarily due to lower operating costs associated with new production from the Banff and Kyle fields. Other International operating costs are mainly fixed in nature and therefore increased on a per barrel basis due to decreased oil production volumes from the Kiame field in Angola.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
DEPLETION, DEPRECIATION AND AMORTIZATION					
Expense ($ millions)	**$ 236.2**	$ 217.1	$ 186.5	**$ 661.4**	$ 442.4
$/boe	**$ 7.11**	$ 6.59	$ 5.83	**$ 6.78**	$ 5.49

Depletion costs increased in the first nine months of 2001 over the comparable period in 2000 due to higher costs associated with the Company's increased emphasis on natural gas drilling and completion in North America and higher depletion costs in the North Sea and Other International segments acquired with Ranger. Per unit depletion costs increased in third quarter 2001 mainly due to higher depletion on properties in the United States and an increase in the expected abandonment costs associated with the Kiame field in Angola.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
ADMINISTRATION EXPENSE					
Net expense ($ millions)	**$ 9.4**	$ 7.9	$ 5.7	**$ 25.6**	$ 16.9
$/boe	**$ 0.28**	$ 0.24	$ 0.18	**$ 0.26**	$ 0.21

September 2001 year to date administration costs have increased from the comparable period in 2000 due to increased staffing levels associated with the Ranger acquisition. Costs increased in the third quarter of 2001 reflecting lower recoveries related to the capital program.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
INTEREST EXPENSE					
Interest expense ($ millions)	**$ 32.2**	$ 34.8	$ 51.1	**$ 106.4**	$ 116.5
$/boe	**$ 0.97**	$ 1.05	$ 1.60	**$ 1.09**	$ 1.45
Average interest rate	**5.35%**	5.63%	6.56%	**5.74%**	6.25%

Interest expense decreased from the first nine months of 2000 and in the third quarter due to lower debt levels and declining interest rates.

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
TAXES ($ millions)					
Taxes other than income tax					
Current	**$ 21.1**	$ 21.0	$ 21.6	**$ 59.2**	$ 27.2
Deferred	**$ (1.3)**	$ (0.7)	$ (4.0)	**$ (1.2)**	$ (4.0)
Current income tax					
North Sea	**$ 16.5**	$ 25.2	$ 19.5	**$ 51.5**	$ 19.5
Large corporation tax	**$ 3.2**	$ 3.3	$ 4.5	**$ 10.4**	$ 10.1
Future income tax	**$ 61.0**	$ 64.5	$ 164.5	**$ 280.7**	$ 333.9
Effective tax rate	**37.6%**	27.0%	43.7%	**34.5%**	39.3%

North Sea current income tax decreased in third quarter 2001 due to decreased earnings before taxes.

Future income tax expense for the nine months ended September 30, 2001 decreased over the comparable period of the previous year due to a reduction in the Alberta corporate income tax rate effective second quarter 2001 and the recognition of the associated $46 million one time reduction in the future income tax liability in that quarter. The future income tax expense decreased from third quarter 2000 as a result of lower earnings before taxes.

	SEPT 30 2001	JUNE 30 2001	DEC 31 2000	SEPT 30 2000
LIQUIDITY AND CAPITAL RESOURCES ($ millions)				
Working capital deficit (surplus)	**$ 154.1**	$ 113.9	$ 77.3	$ (3.9)
Long-term debt	**$ 2,311.8**	$ 2,369.1	$ 2,454.5	$ 2,908.8
Shareholders' equity				
Preferred securities	**$ 118.3**	$ 118.3	$ 118.3	$ 118.3
Share capital and contributed surplus	**$ 1,693.9**	$ 1,683.9	$ 1,692.6	$ 1,681.0
Retained earnings	**$ 1,939.5**	$ 1,832.1	$ 1,406.0	$ 1,182.8
Total shareholders' equity	**$ 3,751.7**	$ 3,634.3	$ 3,216.9	$ 2,982.1
Debt to cash flow (1) (2)	**1.1x**	1.1x	1.3x	1.9x
Debt to book capitalization (1)	**40.1%**	41.4%	45.4%	51.4%
Debt to market capitalization (1)	**33.0%**	30.4%	32.6%	32.2%
After tax return on average common shareholders' equity (2)	**26.4%**	32.1%	32.4%	30.7%
After tax return on average capital employed (2)	**16.4%**	19.2%	18.1%	17.3%

(1) Includes preferred securities as debt equivalents
(2) Based on trailing 12 months activity

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	**JUNE 30 2001**	**SEPT 30 2000**	**SEPT 30 2001**	**SEPT 30 2000**
CAPITAL EXPENDITURES ($ millions)					
Acquisition of Ranger Oil Limited	**$ -**	$ -	$ 1,687.3	**$ -**	$ 1,687.3
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 24.6**	$ 55.5	$ (11.3)	**$ 270.8**	$ 242.9
Land acquisition and retention	**35.8**	21.5	13.7	**85.0**	34.0
Seismic evaluations	**8.6**	20.2	10.2	**65.8**	22.4
Well drilling, completion and equipping	**153.6**	152.8	131.5	**534.8**	398.2
Pipeline and production facilities	**109.7**	105.0	76.7	**326.1**	237.5
Total net reserve replacement expenditures	**$ 332.3**	$ 355.0	$ 220.8	**$ 1,282.5**	$ 935.0
Midstream operations	**16.1**	6.8	-	**51.8**	-
Oil sands	**1.9**	4.8	-	**15.8**	-
Head office	**1.8**	1.4	0.8	**4.7**	5.6
Total net capital expenditures	**$ 352.1**	$ 368.0	$ 221.6	**$ 1,354.8**	$ 940.6
By Segment					
North America	**$ 297.0**	$ 255.4	$ 178.2	**$ 1,130.5**	$ 897.2
North Sea	**32.2**	16.5	25.3	**63.5**	25.3
Other International	**22.9**	96.1	18.1	**160.8**	18.1
	$ 352.1	$ 368.0	$ 221.6	**$ 1,354.8**	$ 940.6

North America capital expenditures include the continuing development of the Ladyfern field with the tie-in of the second Ladyfern well and the completion of a third well waiting to be tied-in. Internationally, expenditures include the acquisition and development of the Acorn/Beechnut field in the North Sea, drilling of a third well in the Kyle field and the continuing development of the Espoir field located offshore West Africa.

SENSITIVITY ANALYSIS

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

	Cash Flow from Operations ($ millions)	**Cash Flow from Operations** (per share) (basic)	**Net Earnings** ($ millions)	**Net Earnings** (per share) (basic)
Price changes				
Oil – US $1.00/bbl [(2)]	$ 98	$ 0.81	$ 69	$ 0.57
Natural gas– Cdn $1.00/mcf [(3)]	$ 250	$ 2.06	$ 150	$ 1.23
Volume changes				
Oil – 10,000 bbls/day	$ 60	$ 0.50	$ 46	$ 0.38
Natural gas – 10 mmcf/day	$ 7	$ 0.06	$ 2	$ 0.02
Exchange rate change [(4)]				
$0.01 increase in Cdn $ in relation to US $	$ 42	$ 0.35	$ 27	$ 0.22
Interest rate change				
1%	$ 18	$ 0.14	$ 11	$ 0.09

[(1)] The sensitivities are calculated based on 2001 third quarter results.
[(2)] The impact of oil collars in place reduce the sensitivity of cash flow from operations to oil price changes below WTI US $19.00 to $72 million ($0.60 per share) and net earnings of $49 million ($0.40 per share).
[(3)] The impact of AECO priced natural gas collars in place reduce the sensitivity of cash flow from operations to natural gas prices below Cdn $3.23 to $209 million ($1.73 per share) and net earnings of $126 million ($1.04 per share).
[(4)] The impact of currency collars in place reduce the sensitivity of cash flow from operations to exchange rate changes above 1.59 US$/Cdn$ to $34 million ($0.28 per share) and net earnings of $22 million ($0.18 per share).
[(5)] For details of hedges in place, see financial statement note 6.

OTHER OPERATING HIGHLIGHTS

	THREE MONTHS ENDED			NINE MONTHS ENDED	
	SEPT 30 2001	JUNE 30 2001	SEPT 30 2000	SEPT 30 2001	SEPT 30 2000
NETBACK ANALYSIS					
Barrel of oil equivalent (6:1)					
Daily production (boe)	**361,029**	362,154	347,447	**356,905**	294,107
Sales price	**$ 24.25**	$ 29.54	$ 31.40	**$ 29.76**	$ 27.20
Royalties	**3.14**	5.03	4.54	**5.10**	3.89
Operating costs	**5.36**	5.57	5.25	**5.60**	4.41
Netback per boe	**15.75**	18.94	21.61	**19.06**	18.90
Administration	**0.28**	0.24	0.18	**0.26**	0.21
Interest	**0.97**	1.05	1.60	**1.09**	1.45
Foreign exchange loss (gain)	**0.02**	0.06	(0.04)	**0.02**	(0.01)
Taxes other than income tax	**0.64**	0.64	0.62	**0.61**	0.32
Current income tax (North Sea)	**0.49**	0.76	0.66	**0.53**	0.26
Current income tax (Large Corporation Tax)	**0.10**	0.10	0.14	**0.11**	0.12
Cash flow per boe	**$ 13.25**	$ 16.09	$ 18.45	**$ 16.44**	$ 16.55

	NINE MONTHS ENDED SEPTEMBER 30, 2001			
	North America	**North Sea**	**Other International**	**Total**
Oil and liquids				
Daily production (bbls)	**169,261**	**36,422**	**3,445**	**209,128**
Sales price	**$ 21.77**	**$ 40.41**	**$ 38.03**	**$ 25.28**
Royalties	**2.47**	**2.29**	**1.02**	**2.41**
Operating costs	**6.89**	**8.50**	**22.61**	**7.43**
Netback ($/bbl)	**$ 12.41**	**$ 29.62**	**$ 14.40**	**$ 15.44**
Natural gas				
Daily production (mmcf)	**876.6**	**10.1**	**-**	**886.7**
Sales price	**$ 6.05**	**$ 2.21**	**$ -**	**$ 6.01**
Royalties	**1.50**	**-**	**-**	**1.49**
Operating costs	**0.50**	**0.69**	**-**	**0.50**
Netback ($/mcf)	**$ 4.05**	**$ 1.52**	**$ -**	**$ 4.02**
Barrel of oil equivalent (6:1)				
Daily production (boe)	**315,355**	**38,105**	**3,445**	**356,905**
Sales price	**$ 28.53**	**$ 39.20**	**$ 38.03**	**$ 29.76**
Royalties	**5.50**	**2.19**	**1.02**	**5.10**
Operating costs	**5.09**	**8.30**	**22.61**	**5.60**
Netback ($/boe)	**$ 17.94**	**$ 28.71**	**$ 14.40**	**$ 19.06**

CONSOLIDATED BALANCE SHEET (millions of Canadian dollars)

	SEPTEMBER 30 2001 (unaudited)	DECEMBER 31 2000 (audited)
Assets		
Current assets		
Cash	**$ 35.0**	$ 28.0
Accounts receivable and prepaid expenses	**511.8**	550.1
Inventories	**31.0**	33.9
	577.8	612.0
Property, plant and equipment, net	**7,943.1**	7,141.5
Deferred charges	**73.4**	22.1
	$ 8,594.3	$ 7,775.6
Liabilities		
Current liabilities		
Accounts payable	**$ 417.8**	$ 301.1
Accrued liabilities	**282.5**	371.7
Current portion of long-term debt (note 3)	**31.6**	16.5
	731.9	689.3
Long-term debt (note 3)	**2,311.8**	2,454.5
Future site restoration	**190.1**	170.5
Future income tax (note 4)	**1,608.8**	1,244.4
	4,842.6	4,558.7
Shareholders' Equity		
Preferred securities	**118.3**	118.3
Share capital and contributed surplus (note 5)	**1,693.9**	1,692.6
Retained earnings	**1,939.5**	1,406.0
	3,751.7	3,216.9
	$ 8,594.3	$ 7,775.6

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

	THREE MONTHS ENDED SEPT 30 2001	THREE MONTHS ENDED SEPT 30 2000	NINE MONTHS ENDED SEPT 30 2001	NINE MONTHS ENDED SEPT 30 2000
Revenue				
Oil and natural gas	**$ 805.5**	$ 1,003.8	**$ 2,899.9**	$ 2,191.6
Less: royalties	**104.2**	145.2	**497.1**	313.6
	701.3	858.6	**2,402.8**	1,878.0
Expenses				
Production	**178.1**	167.6	**546.0**	355.1
Depletion, depreciation and amortization	**236.2**	186.5	**661.4**	442.4
Administration	**9.4**	5.7	**25.6**	16.9
Interest	**32.2**	51.1	**106.4**	116.5
Foreign exchange loss (gain)	**11.2**	(1.0)	**12.3**	-
	467.1	409.9	**1,351.7**	930.9
Earnings Before Taxes	**234.2**	448.7	**1,051.1**	947.1
Taxes other than income tax	**19.8**	17.6	**58.0**	23.2
Current income tax	**19.7**	24.0	**61.9**	29.6
Future income tax (note 4)	**61.0**	164.5	**280.7**	333.9
Net Earnings	**133.7**	242.6	**650.5**	560.4
Dividend on preferred securities, net of tax	**(1.4)**	(1.4)	**(4.3)**	(1.4)
Net Earnings Attributable to Common Shareholders	**$ 132.3**	$ 241.2	**$ 646.2**	$ 559.0
Per common share (note 2)				
Basic	**$ 1.10**	$ 2.04	**$ 5.33**	$ 4.86
Diluted	**$ 1.08**	$ 1.97	**$ 5.13**	$ 4.73
Weighted average common shares outstanding (thousands)(note 2)				
Basic			**121,349**	114,905
Diluted			**126,912**	118,487

CONSOLIDATED STATEMENT OF RETAINED EARNINGS (millions of Canadian dollars)(unaudited)

	NINE MONTHS ENDED SEPT 30 2001	NINE MONTHS ENDED SEPT 30 2000
Balance – Beginning of Period	**$ 1,406.0**	$ 623.8
Net earnings	**650.5**	560.4
Repurchase of common shares (note 5)	**(76.2)**	-
Dividend on common shares (note 5)	**(36.5)**	-
Dividend on preferred securities, net of tax	**(4.3)**	(1.4)
Balance – End of Period	**$ 1,939.5**	$ 1,182.8

CONSOLIDATED STATEMENT OF CASH FLOWS (millions of Canadian dollars, except per share amounts)(unaudited)

	THREE MONTHS ENDED SEPT 30 2001	THREE MONTHS ENDED SEPT 30 2000	NINE MONTHS ENDED SEPT 30 2001	NINE MONTHS ENDED SEPT 30 2000
Operating Activities				
Net earnings	**$ 133.7**	$ 242.6	**$ 650.5**	$ 560.4
Non-cash items				
Depletion, depreciation and amortization	**236.2**	186.5	**661.4**	442.4
Deferred petroleum revenue tax (recovery)	**(1.3)**	(4.0)	**(1.2)**	(4.0)
Future income tax	**61.0**	164.5	**280.7**	333.9
Unrealized foreign exchange loss	**10.4**	0.2	**10.6**	0.7
Cash flow provided from operating activities	**440.0**	589.8	**1,602.0**	1,333.4
Net change in non-cash working capital	**16.7**	(40.6)	**(9.6)**	(66.4)
	456.7	549.2	**1,592.4**	1,267.0
Financing Activities				
Increase (decrease) in long-term debt	**(94.6)**	438.1	**(189.5)**	373.7
Issue of capital stock	**16.0**	13.3	**38.3**	54.1
Repurchase of common shares	**(18.7)**	-	**(113.3)**	-
Dividend on common shares	**(12.1)**	-	**(24.3)**	-
Dividend on preferred securities	**(2.6)**	(2.5)	**(7.7)**	(2.5)
Net change in non-cash working capital	**8.3**	(34.2)	**7.5**	(32.3)
	(103.7)	414.7	**(289.0)**	393.0
Investing Activities				
Expenditures on property, plant and equipment	**(354.0)**	(243.0)	**(1,369.2)**	(966.9)
Corporate acquisitions	**-**	(722.8)	**-**	(722.8)
Net proceeds on sale of property, plant and equipment	**1.9**	21.4	**14.4**	26.3
Net change in non-cash working capital	**2.1**	0.9	**58.4**	23.8
	(350.0)	(943.5)	**(1,296.4)**	(1,639.6)
Increase in Cash	**3.0**	20.4	**7.0**	20.4
Cash – Beginning of Period	**32.0**	0.1	**28.0**	0.1
Cash – End of Period	**$ 35.0**	$ 20.5	**$ 35.0**	$ 20.5
Cash flow per share from operations attributable to common shareholders (note 2)				
Basic	**$ 3.63**	$ 4.97	**$ 13.14**	$ 11.58
Diluted	**$ 3.50**	$ 4.80	**$ 12.62**	$ 11.25
Supplemental disclosure of cash flow information				
Interest paid	**$ 25.8**	$ 39.5	**$ 99.0**	$ 109.8
Taxes paid	**$ 37.8**	$ 26.2	**$ 118.5**	$ 38.2

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

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company as at December 31, 2000, except as described in note 2. The interim consolidated financial statements contain disclosures which are supplemental to the Company's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2000.

2. CHANGE IN ACCOUNTING POLICY

Effective January 1, 2001, the Company adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to the calculation and disclosure of per share amounts. Under the new standard, the treasury stock method of calculating per share amounts is used whereby any proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

In computing diluted per share amounts, 5.6 million common shares were added for the nine months ended September 30, 2001 (September 30, 2000 – 3.6 million common shares) for the dilutive effect of employee stock options, warrants and preferred securities. Dividends on preferred securities were added back to net earnings and cash flow attributable to common shareholders in computing diluted per share amounts.

The new standard has been applied retroactively and prior periods have been restated. The new standard has no effect on basic per share amounts but does affect diluted per share amounts. Had the new standard not been adopted, fully diluted net earnings and cash flow attributable to common shareholders per share for the three months ended September 30, 2001 would have been $1.10 and $3.63 respectively, and for the nine months ended September 30, 2001, would have been $5.33 and $13.14.

3. LONG-TERM DEBT

	September 30 2001	**December 31 2000**
Bank facilities		
Canadian dollar debt	**$ 658.1**	$ 1,445.7
US dollar debt (US $296 million)	**467.4**	444.0
Limited recourse loan	**-**	11.8
Medium term notes	**250.0**	250.0
US debt securities (US $400 million)	**631.6**	-
Senior unsecured notes (US $213 million)	**336.3**	319.5
	2,343.4	2,471.0
Amount due within one year	**31.6**	16.5
	$ 2,311.8	$ 2,454.5

Credit Facilities

(a) Bank Facilities

At September 30, 2001, the Company had unsecured bank credit facilities of approximately $1,837 million comprised of a $100 million operating demand facility, a revolving credit and term loan facility totaling $1,500 million and a revolving credit and term loan facility of US $150 million. During the nine months ended September 30, 2001, the Company had repaid and cancelled two credit facilities totaling $975 million as well as the limited recourse loan of $22.1 million.

(b) US Debt Securities

In July 2001, the Company authorized a US debt securities program in the aggregate principal amount of up to US $1 billion for issue in the United States. The notes bear interest as determined at the date of issue of the notes.

On July 24, 2001, the Company issued US $400 million of US Debt Securities, maturing July 15, 2011 bearing interest at 6.70%. In August 2001, the Company entered into four interest rate swap contracts which convert the fixed rate interest coupon into a floating interest rate (see Note 6 – Interest Rate Swaps).

(c) Medium Term Notes

In July 2001, the Company authorized a new medium term notes program in the aggregate principal amount of up to $1 billion for issue in Canada. The notes bear interest as determined at the date of issue of the notes. No amounts are currently drawn down under this program.

The Company has $250 million of medium term notes outstanding from a previous medium term note program.

4. INCOME TAXES

The Company's future income tax liability has been reduced by $46 million to reflect a reduction in the Alberta corporate income tax rate effective April 1, 2001. The effect of this reduction was recognized in the statement of earnings in the three months ended June 30, 2001.

5. SHARE CAPITAL AND CONTRIBUTED SURPLUS

		September 30 2001		**December 31 2000**
Common shares	**$**	**1,693.9**	$	1,688.0
Warrants		**-**		2.7
Contributed surplus		**-**		1.9
	$	**1,693.9**	$	1,692.6

Issued

	September 30, 2001		
	Number of shares (000's)		**Amount**
Common shares			
Balance – January 1, 2001	**122,279**	**$**	**1,688.0**
Exercise of stock options	**840**		**24.8**
Exercise of warrants	**455**		**16.3**
Repurchase of shares under Normal Course Issuer Bid	**(2,538)**		**(35.2)**
Balance – September 30, 2001	**121,036**	**$**	**1,693.9**
Warrants			
Balance – January 1, 2001	**465**	**$**	**2.7**
Exercised during the period	**(455)**		**(2.7)**
Expired during the period	**(10)**		**(0.0)**
Balance – September 30, 2001	**-**	**$**	**-**

Stock options

	September 30, 2001		
	Share options (000's)		Weighted average exercise price
Outstanding – January 1, 2001	**10,664**	**$**	**32.78**
Granted	**3,300**		**40.92**
Exercised	**(840)**		**29.54**
Forfeited	**(732)**		**38.73**
Outstanding – September 30, 2001	**12,392**	**$**	**34.81**
Exercisable – September 30, 2001	**3,151**	**$**	**30.64**

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 percent 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 September 30, 2001, the Company had purchased 2,537,800 common shares for a total cost of $113.3 million.

Dividend policy

On January 17, 2001, the Company announced the payment of a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year. The initial payment was made on April 1, 2001 with the third payment made on October 1, 2001 to shareholders of record on September 14, 2001.

6. FINANCIAL INSTRUMENTS

The Company uses certain derivative financial instruments to manage its foreign currency and commodity price 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 hedges outstanding:

	Term	Volume	Price	Index
Oil				
Oil price collars	Oct. 2001 – Dec. 2001	100,000 bbls/day	US $26.52 – US $30.44	WTI
	Jan. 2002 – Mar. 2002	31,000 bbls/day	US $19.00 – US $22.39	WTI
	Apr. 2002 – Jun. 2002	15,000 bbls/day	US $19.00 – US $22.63	WTI
	Jan. 2002 – Dec. 2002	35,500 bbls/day	US $20.55 – US $26.00	WTI
Brent differential swaps	Oct. 2001 – Dec. 2001	17,000 bbls/day	US $1.16	Dated Brent/WTI
	Jan. 2002 – Dec. 2002	15,000 bbls/day	US $1.38	Dated Brent/WTI
Natural Gas				
Sumas fixed	Oct. 2001 – Oct. 2002	20,000 mmbtu/day	Cdn $2.85	Sumas
Empress – NYMEX differential swap	Oct. 2001 – Oct. 2006	5,500 mmbtu/day	US $0.73	Empress/NYMEX
NYMEX swaps	Oct. 2001	30,000 mmbtu/day	US $1.75	NYMEX
	Oct. 2001 – Oct. 2006	10,000 mmbtu/day	Cdn $2.66	NYMEX
AECO collars	Jan. 2002 – Mar. 2002	90,000 GJ/day	Cdn $3.85 – Cdn $5.04	AECO
	Apr. 2002 – Jun. 2002	100,000 GJ/day	Cdn $3.75 – Cdn $4.62	AECO
	Jan. 2002 – Jun. 2002	100,000 GJ/day	Cdn $3.23 – Cdn $4.00	AECO

	Term	Amount ($ millions)	Average Exchange Rate (US $/Cdn $)
Foreign Currency			
Currency fixed	Oct. 2001 – Dec. 2001	US $11.4 /month	1.33
	Jan. 2002 – Oct. 2002	US $0.4 /month	1.37
Currency collars	Oct. 2001 – May 2003	US $4.2 /month	1.43 – 1.53
	Oct. 2001 – Aug. 2004	US $25.0/month	1.51 – 1.59

	Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest Rate				
Swaps – fixed to floating	Oct. 2001 – Jul. 2004	US $200	6.70%	Libor + 2.09%
	Oct. 2001 – Jul. 2006	US $200	6.70%	Libor + 1.58%

7. SEGMENTED INFORMATION

	THREE MONTHS ENDED SEPT 30		NINE MONTHS ENDED SEPT 30	
	2001	**2000**	**2001**	**2000**
Revenue				
North America	**$ 651.7**	$ 827.9	**$ 2,456.3**	$ 2,015.7
North Sea	**141.6**	157.7	**407.8**	157.7
Other International	**12.2**	18.2	**35.8**	18.2
	805.5	1,003.8	**2,899.9**	2,191.6
Net Earnings				
North America	**$ 116.1**	$ 167.1	**$ 553.9**	$ 484.9
North Sea	**22.2**	67.2	**101.3**	67.2
Other International	**(4.6)**	8.3	**(4.7)**	8.3
	133.7	242.6	**650.5**	560.4
Dividend on preferred securities, net of tax	**(1.4)**	(1.4)	**(4.3)**	(1.4)
Net Earnings Attributable to Common Shareholders	**$ 132.3**	$ 241.2	**$ 646.2**	$ 559.0
Additions to Property, Plant and Equipment				
North America	**$ 297.0**	$ 178.2	**$ 1,216.6**	$ 897.2
North Sea	**32.2**	25.3	**63.5**	25.3
Other International	**22.9**	18.1	**160.8**	18.1
	$ 352.1	$ 221.6	**$ 1,440.9**	$ 940.6

Property, plant and equipment and future income taxes payable have been increased by $86.1 million to provide for the tax effect of the acquisition of non-tax base assets in North America in first nine months of 2001.

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, 2001.

Interest coverage (times)	
Net earnings	**10.0** [(1)]
Cash flow	**15.7** [(2)]

[(1)] Net earnings plus income taxes and interest expense; divided by interest expense.
[(2)] Cash flow 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 principal amount of $118.3 million of 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 earnings coverage ratio for the 12 month period ended September 30, 2001 would be 9.4 and the cash flow coverage ratio for the 12 month period ended September 30, 2001 would be 14.7.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time, Wednesday, November 7, 2001. The North America conference call number is 1-877-871-4105 and the outside North America conference call number is 1-416-641-6450. 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 please call 1-800-473-0602 and for those outside North America call 1-905-502-3723.

Media are invited to participate in listen only mode.

Replay: A taped rebroadcast will be available until November 14, 2001 (inclusive). To access postview in North America dial 1-800-558-5253 and enter the passcode 19930705. Those outside of North America dial 1-416-626-4100 and enter the reservation number 19936879.

FOURTH QUARTER 2001 RESULTS

Fourth quarter 2001 results are scheduled for release Wednesday, February 27, 2002. A conference call will be held on this date at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time.

For more information, please contact:

ALLAN P. MARKIN	**JOHN G. LANGILLE**	**STEVE W. LAUT**
Chairman	President	Senior Vice-President, Operations

CANADIAN NATURAL RESOURCES LIMITED
2500, 855 – 2nd Street S.W., Calgary, Alberta, T2P 4J8
Telephone: (403) 517-6700 **Facsimile:** (403) 517-7350
Email: investor.relations@cnrl.com **Website:** www.cnrl.com

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