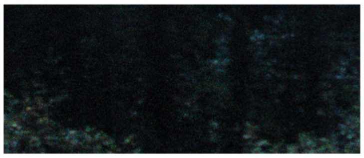
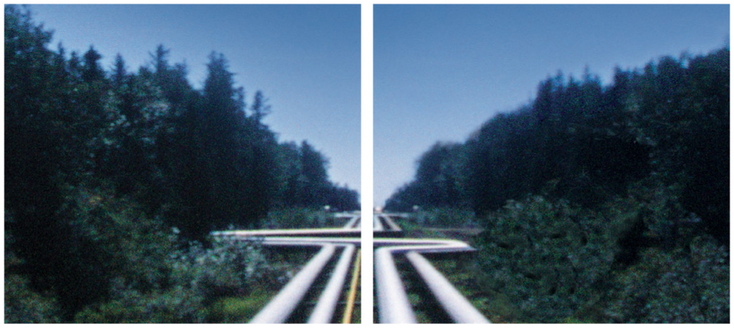
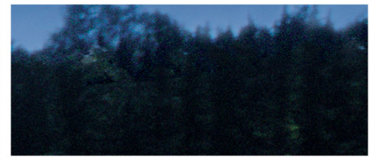

Press Release

May 5, 2004

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD PRODUCTION, NOW IN EXCESS OF ONE HALF MILLION BOES PER DAY AND STRONG QUARTERLY RESULTS

CALGARY, ALBERTA – MAY 5, 2004 – FOR IMMEDIATE RELEASE

In commenting on first quarter 2004 results, Canadian Natural's Chairman, Allan Markin, stated "We have achieved a very significant milestone this quarter with exit and current production volumes now in excess of half a million boes per day. This has been accomplished in less than 15 years of operation."

Canadian Natural's Chief Operating Officer, Steve Laut, in commenting on operations stated "Our first quarter drilling program was the largest in the history of Canadian Natural, which saw us contracting up to 64 drilling rigs per day. As a result of our development activities, our current worldwide natural gas production levels are in excess of 1.45 bcf/d and crude oil and NGLs production is in excess of 276 mbbl/d. The acquisition of heavy oil properties in eastern Alberta and natural gas properties in Northeast British Columbia both represent core area consolidation opportunities with exploitation and exploration upside. As a result of these transactions, our project portfolio is stronger and our ability to finance major development projects is enhanced"

Canadian Natural's President, John Langille, in commenting on the financial results of the first quarter stated "Growing production results combined with strong commodity prices have yielded exceptional cash flow and positioned us to build an even stronger Canadian Natural. We have taken some of our excess cash flows and reinvested them into properties that will payout in short order and provide free cash flow during the Horizon Project construction years."

HIGHLIGHTS OF THE FIRST QUARTER

- Production rates exited the quarter in excess of 500,000 boe/d, before royalties.
- Record quarterly crude oil and NGLs sales of 261 mbbl/d, before royalties (237 mbbl/d, net of royalties).
- Natural gas sales of 1,294 mmcf/d, before royalties (1,029 mmcf/d, net of royalties), representing 45 percent of equivalent production during the quarter.
- Cash flow of $848 million ($6.32 per common share) compared with $906 million ($6.76 per common share) in the first quarter of 2003 and $734 million ($5.48 per common share) in the previous quarter.
- Net earnings of $258 million ($1.92 per common share) compared with $427 million ($3.19 per common share) for the first quarter of 2003 and $250 million ($1.87 per common share) in the previous quarter. Adjusted net earnings from operations a non Generally Accepted Accounting Principle ("GAAP") term, amounted to $339 million ($2.53 per common share) compared with $324 million ($2.42 per common share) for the first quarter of 2003 and $201 million ($1.50 per common share) in the previous quarter.
- Successfully completed the $471 million acquisition of the Petrovera Partnership ("Petrovera") with an effective date of February 1, 2004. This strategic acquisition added 27.5 mbbl/d (18.4 mbbl/d average during the first quarter) of heavy crude oil and 9 mmcf/d (6 mmcf/d average during the first quarter) of natural gas together with royalty interest volumes of 1.2 mbbl/d of heavy crude oil and 2 mmcf/d of natural gas.
- Received regulatory approvals for the Horizon Oil Sands Project from the Alberta Energy and Utilities Board as well as the Alberta Provincial Cabinet and the Canadian Federal Cabinet.

- Capital expenditures of $1.5 billion, reflecting the high activity levels associated with winter drilling areas and the Petrovera acquisition. During the quarter, Canadian Natural drilled 839 wells, including 358 natural gas wells.

- Extended its Normal Course Issuer Bid for a further 12-month period through the facilities of the Toronto Stock Exchange and the New York Stock Exchange for the purchase of up to 5 percent of the Company's common shares outstanding (approximately 6.7 million common shares) at the market price, if and when acquired.

- To increase the liquidity of its common shares, the Board of Directors has proposed to the shareholders that the Company's common shares be subdivided on the basis of 2:1. The proposal will be voted on at the Annual and Special Meeting of Shareholders to be held on May 6, 2004.

- Increased the quarterly dividend by 33 percent to $0.20 per common share on a pre-split basis ($0.10 per common share on a post split basis), commencing with the April 1, 2004 payment.

- Subsequent to the first quarter, successfully negotiated the acquisition of natural gas assets located in the Company's core region of Northeast British Columbia and an extension of its core region in the Foothills area of Western Alberta for $280 million. The acquisition provides Foothills exploration acreage to augment Canadian Natural's increasing exploration efforts in the area.

ADJUSTED NET EARNINGS FROM OPERATIONS

The following reconciliation lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results for each of the periods reported. Adjusted net earnings from operations is a non-GAAP term that the Company utilizes to evaluate its performance and that of its business segments.

($ millions, except per common share amounts)

	Three Months Ended		
	March 31 2004	December 31 2003	March 31 2003
Net earnings attributable to common shareholders as reported	**$ 258**	$ 250	$ 427
Unrealized foreign exchange loss (gain) [1]	**37**	(64)	(96)
Unrealized foreign exchange loss (gain) on preferred securities[1]	**1**	(4)	(7)
Unrealized risk management activities[2]	**68**	-	-
Effect of statutory tax rate changes on future income tax liabilities[3]	**(66)**	(31)	-
Stock-based compensation expense [4]	**41**	43	-
Reduction in carrying value of foreign assets[5]	**-**	7	-
Adjusted net earnings from operations attributable to common shareholders	**$ 339**	$ 201	$ 324
Per share – basic	**$ 2.53**	$ 1.50	$ 2.42
– diluted	**$ 2.51**	$ 1.49	$ 2.34

(1) *Unrealized foreign exchange gains and losses result primarily from the translation of long-term debt and preferred securities to period end exchange rates and are immediately recognized in net earnings attributable to common shareholders.*

(2) *Effective January 1, 2004, the Company adopted a new accounting standard whereby financial instruments not designated as hedges are valued at fair value on its balance sheet, with changes in fair value, net of taxes, flowing through earnings. The realized value may be different than reflected in these financial statements due to changes in the underlying items hedged, primarily crude oil and natural gas prices.*

(3) *All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. During the first quarter of 2004, a Canadian province introduced legislation to reduce its corporate income tax rate. During 2003, the Canadian Government introduced several income tax changes, including rate reductions, for the resource industry.*

(4) *Commencing with the second quarter of 2003, the Company modified its employee stock option plan to provide for a cash payment option. The intrinsic value of the outstanding stock options is recorded as a liability on the Company's balance sheet and quarterly changes in the intrinsic value flow through earnings. In the first quarter of 2004, a charge of $41 million after taxes ($61 million before taxes) was recognized. In the fourth quarter of 2003, a charge of $43 million after taxes ($63 million before taxes) was recognized.*

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

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 crude oil, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Canadian Natural has prospectively adopted a new reporting practice of netting royalty income against royalty expense rather than sales volumes and revenue. The result is that approximately 8 mmcf/d of natural gas and 1.7 mbbl/d of crude oil is not reported as production volumes, as was previous practice. While not material, this prospective reporting may result in minor changes in certain reporting metrics such as production volumes and "per boe" financial results.

Average natural gas production levels in the first quarter of 2004 increased by 3 percent over the previous quarter, reflecting the increased drilling activity in winter-access only areas offset by the reporting change noted above. During the quarter, 358 natural gas wells were drilled. This drilling activity was affected by extreme cold during the month of January, effectively shifting tie in and first production from many wells by several weeks. As a result of this, approximately 45 mmcf/d of natural gas was not tied in during the quarter as expected. This production will be tied in following break-up. Natural gas production levels increased significantly during the quarter with entry to exit growth of over 100 mmcf/d. Current production volumes are in excess of 1,450 mmcf/d of natural gas.

Production of crude oil and NGLs during the first quarter of 2004 totaled 261 mbbl/d, a new quarterly record. Entry to exit production increased from 247 mbbl/d to 276 mbbl/d, reflecting past drilling programs and the Petrovera acquisition. The Company expects production from the first quarter drilling program to come on-stream during the second and third quarters.

The Company's production composition, before royalties, is as follows:

	Q1 2004		Q4 2003		Q1 2003	
	mboe/d	%	mboe/d	%	mboe/d	%
Natural gas	**215.6**	**45**	211.7	46	218.4	48
Light oil and NGLs	**117.1**	**25**	115.4	25	112.6	25
Pelican Lake oil	**19.9**	**4**	21.5	5	25.1	5
Primary heavy oil	**89.8**	**19**	71.0	16	60.4	13
Thermal heavy oil	**34.5**	**7**	36.4	8	39.5	9
Total	**476.9**	**100**	456.0	100	456.0	100

Following the acquisition of Petrovera and natural gas resource properties in Northeast British Columbia, the Company expects production levels, before royalties, in 2004 to average 1,350 to 1,405 mmcf/d of natural gas and 265 to 283 mbbl/d of oil and liquids. Second quarter 2004 production guidance, before royalties, for natural gas is 1,427 to 1,455 mmcf/d of natural gas and 264 to 282 mbbl/d of oil and liquids. Detailed guidance on production levels and operating costs can be found on the Company's website (www.cnrl.com/investor/guidance.htm).

DRILLING ACTIVITY (number of wells)

	Three Months Ended March 31			
	2004		2003	
	Gross	**Net**	Gross	Net
Oil	**148**	**143**	124	116
Natural gas	**395**	**358**	261	244
Dry	**74**	**70**	24	23
Subtotal	**617**	**571**	409	383
Stratigraphic test/service wells	**269**	**268**	367	366
Total	**886**	**839**	776	749
Success rate (excluding strat tests/service wells)		**88%**		94%

During the quarter, Canadian Natural drilled 839 net wells, including 268 stratigraphic test and service wells, representing the most active quarterly drilling program in the Company's history. Canadian Natural drilled 358 net wells targeting natural gas, also a quarterly record. In Northeast British Columbia, 173 wells targeting natural gas were drilled, including 86 shallow Notikewin wells that achieved a 96 percent success rate. In Northwest Alberta, 75 wells targeting natural gas were drilled including 37 Cardium wells with a 100 percent success rate. The Northeast British Columbia and Northwest Alberta core regions represent the high growth potential natural gas areas of the Company.

The Company also drilled 143 net wells, including 33 net wells drilled by Petrovera, targeting crude oil and NGLs during the first quarter 2004. These wells were concentrated in the Company's crude oil region of North Alberta where 76 primary heavy oil and 20 Pelican Lake wells were drilled. Also included in this figure were 19 high-pressure horizontal thermal oil wells that were drilled and completed at Primrose as part of the 2004 development strategy of the area.

Finally, 180 stratigraphic test wells were drilled on the oil sands leases in Horizon Oil Sands Project and 79 wells in Primrose and Pelican Lake.

The total success rate for Canadian Natural's drilling program was 88 percent, excluding stratigraphic test and service wells. These excellent results reflect the disciplined approach that the Company takes in its exploitation and development programs and the strength of our asset base.

Pricing

Detailed reviews of benchmark pricing and sensitivity to product pricing, currency exchange, and interest rates are provided in Management's Discussion and Analysis. Product pricing as measured in US dollars for both crude oil and natural gas increased during the first quarter of 2004 when compared to either the previous quarter or the corresponding quarter of 2003. As expected, heavy crude oil differentials remained wide in absolute dollars but were lower than the long-term average as a percentage of WTI benchmark price. While crude oil and natural gas benchmark prices measured in Canadian dollars increased compared with the previous quarter, realized prices were lower than the corresponding quarter of last year due to the strengthening of the Canadian dollar in relation to the U.S. dollar. By illustration, the gross price realization per barrel of oil equivalent was C$35.88/boe during the first quarter of 2004, up from the C$30.43/boe realized during the previous quarter but down from the C$42.83/boe realized during the first quarter of 2003.

Canadian Natural continues to deliver on its heavy crude oil marketing strategy and in particular its bitumen diluted with synthetic light crude oil or "Synbit" product. The Company is currently marketing 45,000 bbl/d of Synbit to refiners located in the U.S. Midwest and plans to expand this effort throughout 2004 to build a solid new market for heavy and synthetic crudes. This incremental market will enhance Canadian Natural's ability to profitably expand heavy crude oil production.

The Company utilizes risk management instruments on a portion of its production in an effort to reduce volatility and provide greater certainty that operating cash flows are available to fund capital expenditures. Generally, costless collars are utilized against benchmark commodity prices as well as currency exposures. The details of these risk management instrument positions are reported in note 11 of the consolidated financial statements. In accordance with new financial reporting standards, Canadian Natural also records mark-to-market valuations of economic price risk management instruments applicable to future production. These amounts represent valuations at the balance sheet date should the Company wish to monetize the risk management positions. However, it is the Company's intention to maintain these risk management positions over the production periods noted and therefore the ultimate cost or benefit of the program is indeterminable and will be realized over time. These risk management positions and the mark-to-market are detailed in Management's Discussion and Analysis.

Indicative commodity prices as of May 4, 2004 include a one year forward reference WTI price of US$35.90/bbl, a NYMEX natural gas price of US$6.34/mmbtu and a Lloyd Blend heavy oil differential of US$10/bbl. The Bank of Canada noon day exchange rate for this date was US$0.73 equals C$1.00.

ACTIVITY BY CORE REGION

	Net Undeveloped Land as of March 31, 2004	**Drilling Activity Three months ended March 31, 2004**
	(thousands of net acres)	(net wells)
Northeast British Columbia	**1,540**	**176**
Northwest Alberta	**1,633**	**76**
North Alberta	**6,359**	**312**
South Alberta	**643**	**79**
Southeast Saskatchewan	**148**	**11**
Horizon Oil Sands Project	**117**	**180**
United Kingdom North Sea	**573**	**5**
Offshore West Africa	**943**	**0**
	11,956	**839**

North American Natural Gas

Canadian Natural continues its exploration and development activities in the highly prospective core region of Northeast British Columbia. In the Helmet area, a total of 52 horizontal wells targeting tight natural gas zones were drilled, while in the Fort St. John Block, 86 Notikewin shallow wells and 4 deeper targets were drilled. The Notikewin wells drilled to date are producing at rates of 0.4 mmcf/d to 1.0 mmcf/d of natural gas, slightly better than original expectations.

The Company drilled four deep natural gas exploration targets during the quarter with 100 percent success and production rate expectations of between 2 mmcf/d and 15 mmcf/d of natural gas per well. The overall success rate for this core region was 94 percent.

In the Cardium-oriented southern portion of the Northwest Alberta core region, a total of 37 wells targeting natural gas were drilled with a success rate of 100 percent. In addition to the Cardium drilling, a total of 38 wells targeting other natural gas formations were drilled in this core region with a success rate of 79 percent.

Subsequent to the quarter end, the Company completed an acquisition of certain resource properties producing approximately 68 mmcf/d of natural gas located in Northeast British Columbia and Northwest Alberta for consideration of $280 million. The properties include a further ownership interest in the Ladyfern natural gas field, complementing Canadian Natural's existing holdings. The acquisition also provided over 415 thousand acres of developed and undeveloped land facilitating the expansion of existing Gething and Notikewin plays as well as an expanded presence in the Foothills areas of Alberta and British Columbia. The Foothills area is characterized by large, high-rate, deep prospects and are considered higher risk and higher reward targets. The Company has been building a team of exploration specialists to take advantage of this opportunity and has already identified at least four targets for drilling.

Canadian Natural was also active in its traditional natural gas core regions of North Alberta and South Alberta where it dominates a vast land base, drilling 100 and 77 wells targeting natural gas respectively in the first quarter. The Company continues to develop its resources in these regions which account for approximately 40 to 45 percent of daily corporate natural gas production.

North American Crude Oil and NGLs

Canadian Natural continues the disciplined development of its vast heavy crude oil resources. As has been previously articulated, these assets will be developed as heavy crude oil markets permit. In addition to the expansion of markets for Synbit, the Company is working with refiners to expand heavy crude oil conversion capacity of refineries in the Midwest United States; and is working with pipeline companies to develop new capacity to the Canadian west coast where crude cargoes could be sold on a world-wide basis. Over the long term, as these opportunities come to fruition, Canadian Natural will accelerate development of its bitumen resources. As part of this development plan, the Company is continuing with its Primrose thermal project which includes the Primrose North expansion project, drilling additional wells in the Primrose South project augmenting existing production, and converting all of the existing wells from low pressure to high pressure steaming. At Primrose south drilling of the two new phases that commenced in 2003 was completed. Steaming of these new phases is underway and production will commence in mid 2004.

In the first quarter, the Company drilled 76 heavy crude oil wells, including 33 wells drilled relating to the acquisition of Petrovera, 20 Pelican Lake oil wells and 19 high-pressure cyclic steam thermal crude oil wells at Primrose. The majority of these wells were drilled late in the first quarter as the drilling program was focused on natural gas early in the quarter. The majority of the North American crude oil drilling program will occur in the second and third quarter of 2004 as many of the Company's oil areas are accessible year round.

During the first quarter, the Company completed its acquisition of Petrovera. This acquisition fits Canadian Natural's strategy of dominating its core areas and related infrastructure as all of the properties acquired by the Company are located in its heavy oil core area. Canadian Natural expects operating cost reductions through synergies with its own existing facilities including additional throughput in its 100 percent owned ECHO pipeline. In addition, approximately 300 new well locations and over 400 well recompletion opportunities have been identified on these lands and will be added into project inventory. This $467 million acquisition included 27.5 mbbl/d of heavy crude oil and 9 mmcf/d of natural gas and was effective February 1, 2004.

The Pelican Lake enhanced oil recovery project also continues. This project seeks to significantly increase recovery efficiency on this vast blanket sand in North Alberta. Quarterly production declines reflected lower drilling activity and the conversion of additional producer wells to waterflood injection wells. The project to date is on schedule and on budget and waterflood response to date has been positive.

Horizon Oil Sands Project

Canadian Natural continues to target acceptable certainty of forecasted capital costs for the Horizon Oil Sands Project ("Horizon Project") for fall, 2004. The Company's approach is to have a higher level of project definition and detailed engineering than has been completed by predecessor projects. This, along with Canadian Natural retaining the role as project manager and breaking the project into numerous manageable pieces which can be individually bid out to different engineering firms represents a significant departure from past industry norms. Ideally, many of these bids are expected to be completed on a lump-sum or fixed cost basis, further providing certainty of costs. Once acceptable certainty of forecasted capital costs is obtained, the Company's management will be in a position to recommend the sanctioning of the project. While completion on a timely basis is important, the Company views determination of certainty of forecasted costs to be a higher priority and will allow some flexibility in dates in order to control costs.

During the quarter, the Company received regulatory approvals from the Alberta Energy and Utilities Board as well as the Alberta Provincial Cabinet and the Canadian Federal Cabinet.

Also during the quarter, work on the third phase of engineering, Engineering Design Specification continued and some preconstruction site preparation was completed. Additionally, contracts to develop the gravel supply and construct drainage for the plant site area were signed.

The Company currently employs over 700 experienced staff and contractor professionals on this project, including 140 employees focused solely on the development of the Project Execution Plan. As owner manager, Canadian Natural will develop and execute this plan ensuring delivery of the project on budget.

North Sea

Canadian Natural continues its successful infill drilling, recompletion and waterflood optimization programs at the Ninian and Murchison platforms. During the first quarter, the Company commenced the Lyell Field development with one well being spudded late in the quarter. Increased production from this field is expected late in the second quarter of 2004. The successful infill drilling program at the Ninian Field also continued with 4 wells drilled during the quarter. First quarter production levels reflect the 21 day shutdown of the Murchison platform for routine planned maintenance. Routine maintenance activities are scheduled for the Ninian Platforms during the second quarter of 2004.

Also during the quarter Canadian Natural continued plans for its natural gas reinjection project at the Banff field in the Central North Sea. This project is expected to increase overall recovery of hydrocarbons, but will result in lower natural gas production volumes during the latter half of 2004.

Canadian Natural remains excited about the exploitation prospects that exist in the North Sea and will continue to target accretive acquisitions with exploitation upside potential.

Offshore West Africa

The development of the Baobab Field offshore Côte d'Ivoire continued on time and on budget. The development will include five production wells, two water injection wells and related subsea infrastructure. Crude oil will be produced to a Floating Production, Storage and Offtake ("FPSO") vessel currently being fabricated in Singapore.

The planned development of the West Espoir field continued with sanctioning of the final project expected by mid year. Current plans provide for approximately 7,500 bbl/d of crude oil and 22 mmcf/d of natural gas production net to Canadian Natural in spring 2006 through existing FPSO facilities located at East Espoir. Delineation drilling of the Acajou satellite pool discovered in 2003 is expected for the fourth quarter of 2004. If sufficient reserves are identified, this pool would also be tied back to the East Espoir FPSO. Additional geological reviews on other Canadian Natural lands is yielding exploration targets, one of which is currently expected to be drilled during 2005.

Finally, Canadian Natural continues to reprocess seismic on Block 16 located offshore Angola to optimize its next drilling location. The incorporation of data from the unsuccessful well drilled in late 2003 will help reduce exploration risks on the next well, currently expected to be drilled in early 2005. Block 16 represents a high risk/high impact exploration development for the Company in one of the most prolific oil regions of the world.

FINANCIAL REVIEW

Canadian Natural is committed to maintaining its 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. The Company continues to build the necessary financial capacity to maximize ownership in the Horizon Project.

During the first quarter of 2004, strong operational results and product pricing enabled the Company to maintain debt levels at approximately 34 percent of capitalization despite a very significant first quarter drilling program and the acquisition of Petrovera. Corporate debt to cash flow was approximately 1.0 times versus 0.9 times recorded at year end 2003, while debt to EBITDA was 1.0 times compared with 0.8 times at December 31, 2003.

During the first quarter of 2004, Canadian Natural extended its normal course issuer bid program administered through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"). This program provides for the repurchase and cancellation of up to 6,690,385 shares until January 23, 2005. To date, no shares have been repurchased under these facilities.

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

In order to increase the liquidity of its common shares, the Board of Directors has recommended to its shareholders to subdivide the Company's issued and outstanding common shares on a 2 for 1 basis, which will result in an increase in the Company's total issued and outstanding common shares to approximately 268 million common shares. This recommendation will be voted on by the shareholders at the Annual and Special Meeting of Shareholders to be held on May 6, 2004. If approved, it is expected that the additional common shares will be issued on or about May 28, 2004.

Finally, the Company has used excess cash flows derived from higher than expected commodity prices to selectively acquire future cash flow generating properties in its core regions. These targeted acquisitions provide relatively quick repayment of initial investments and will provide additional free cash flow generation capability during the heavy capital spending years of Horizon construction. Both the Petrovera acquisition and the second quarter acquisition of natural gas properties meet these reinvestment criteria and will enhance Canadian Natural's ability to maximizing its ownership in the Horizon Project. This expansion of conventional assets also helps reduce the sole project risk exposure associated with this major development project.

Special note regarding forward-looking statements

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company "believes", "anticipates", "expects", "plans", "estimates", or words of a similar nature. The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition, availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Special note regarding non-GAAP financial measures

Management's discussion and analysis includes references to financial measures commonly used in the oil and gas industry, such as cash flow, cash flow per share and EBITDA (net earnings before interest, taxes, depreciation depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activity). These financial measures are not defined by generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate the performance of the Company and its business segments. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

MANAGEMENT’S DISCUSSION AND ANALYSIS

Management’s discussion and analysis (“MD&A”) of the financial condition and results of operations of Canadian Natural Resources Limited (“Canadian Natural” or the “Company”), should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2004 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2003.

All dollar amounts, except per common share data, are referenced in millions of Canadian dollars, except where noted otherwise. The calculation of barrels of oil equivalent (“boe”) is based on a conversion ratio of 6 thousand cubic feet of natural gas to one barrel of oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

Production volumes are the Company’s interest before royalties, and realized prices exclude the effect of hedging gains and losses, except where noted otherwise.

CHANGE IN ACCOUNTING POLICIES

Asset Retirement Obligations

On January 1, 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountants’ (“CICA”) new Handbook Section 3110, “Asset Retirement Obligations”. The Section requires the recognition of the fair value of the asset retirement obligation for related long-term assets as a liability. Retirement costs equal to the discounted retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. This new standard was adopted retroactively and prior period comparative balances have been restated. The effects on the Company’s consolidated financial statements resulting from the adoption of the standard are discussed in notes 2 and 5 of the consolidated financial statements.

Risk Management Activities

On January 1, 2004, the Company prospectively adopted the CICA’s Accounting Guideline 13, “Hedging Relationships” and EIC 128, “Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments”. Guideline 13 and EIC 128 require that financial instruments that are not designated as hedges be recorded on the Company’s consolidated balance sheet at fair value on the date thereof, with subsequent changes in fair value recorded in earnings on a quarterly reporting basis. Adoption of Guideline 13 and EIC 128 resulted in the Company recognizing an unrealized mark-to-market loss of $102 million ($68 million, net of tax) in the first quarter relating to its financial instruments. The unrealized loss assumes that all unsettled derivative financial instruments were settled on March 31, 2004 and were valued based on market conditions existing at the point in time. As a result of the adoption of this standard, the Company expects the volatility in its net earnings to increase, which is directly attributable to the corresponding volatility in crude oil and natural gas prices and the unsettled derivative financial instruments. The effects on the Company’s consolidated financial statements are discussed later in the MD&A and in notes 2 and 5 of the consolidated financial statements.

ACQUISITION

In February, 2004, the Company acquired certain resource properties in its North Alberta core region, collectively known as the Petrovera Partnership (“Petrovera”), for $471 million. At the time of the acquisition, production from the acquired properties was approximately 27,500 bbl/d of heavy crude oil and 9 mmcf/d of natural gas. Strategically, the acquisition fits with the Company’s objective of dominating its core areas and related infrastructure. The Company expects to achieve production expense reductions through synergies with its existing facilities, including additional throughput in its 100% owned ECHO Pipeline. The acquisition is included in the results of operations commencing February 2004.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003[1]	Mar 31 2003[1]
Revenue	**$ 1,638**	$ 1,377	$ 1,840
Net earnings attributable to common shareholders[2]	**$ 258**	$ 250	$ 427
Per common share – basic	**$ 1.92**	$ 1.87	$ 3.19
– diluted	**$ 1.92**	$ 1.82	$ 3.03
Cash flow from operations attributable to common shareholders[3]	**$ 848**	$ 734	$ 906
Per common share – basic	**$ 6.32**	$ 5.48	$ 6.76
– diluted	**$ 6.27**	$ 5.42	$ 6.53
Business Combination	**$ 471**	$ -	$ -
Capital expenditures, net of dispositions	**$ 1,022**	$ 662	$ 813

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

(2) *After dividend and revaluation of preferred securities.*

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

	Three months ended		
($ millions)	*Mar 31 2004*	*Dec 31 2003*	*Mar 31 2003*
Net earnings attributable to common shareholders	*$* ***258***	*$ 250*	*$ 427*
Non-cash items:			
Future tax on dividend on preferred securities	***(1)***	*(1)*	*(1)*
Revaluation of preferred securities, net of tax	***1***	*(4)*	*(7)*
Stock-based compensation expense	***56***	*63*	*-*
Depletion, depreciation and amortization	***389***	*391*	*361*
Accretion of asset retirement obligation	***11***	*16*	*15*
Unrealized risk management activities	***102***	*-*	*-*
Unrealized foreign exchange loss (gain)	***46***	*(81)*	*(119)*
Deferred petroleum revenue tax (recovery)	***4***	*(17)*	*3*
Future income tax (recovery) expense	***(18)***	*117*	*227*
Cash flow from operations attributable to common shareholders	*$* ***848***	*$ 734*	*$ 906*

The Company recorded strong levels of net earnings and cash flow for the three months ended March 31, 2004 by continuing to follow its defined growth strategy to create shareholder value. The Company continues to make significant progress on its larger, future-growth projects while maintaining its focus on existing assets. Net earnings for the quarter decreased 40% to $258 million from $427 million in the prior year, but increased 3% from the prior quarter. Cash flow decreased 6% to $848 million from $906 million in prior year, but increased 16% from the prior quarter. The decrease in net earnings and cash flow in the first quarter of 2004 compared to the first quarter of 2003 was a result of lower prices for crude oil, NGLs and natural gas. The decrease in net earnings in the first quarter of 2004 also reflected an unrealized expense related to the mark-to-market of the Company's financial instruments and an expense related to stock-based compensation costs, partially offset by future income tax recovery due to provincial income tax rate reductions. The first quarter 2004 results also include a $46 million unrealized foreign exchange loss on the Company's US dollar denominated debt compared to a $119 million unrealized foreign exchange gain in the prior year due to fluctuations in the Canadian dollar.

OPERATING HIGHLIGHTS

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Crude oil and NGLs ($/bbl, except daily production)			
Daily production (bbl/d)	**261,286**	244,262	237,560
Sales price (1)	**$ 34.21**	$ 29.47	$ 39.37
Royalties	**2.91**	2.22	3.56
Production expense	**9.58**	9.45	10.79
Netback	**$ 21.72**	$ 17.80	$ 25.02
Natural gas ($/mcf, except daily production)			
Daily production (mmcf/d)	**1,294**	1,270	1,310
Sales price (1)	**$ 6.31**	$ 5.26	$ 7.75
Royalties	**1.27**	1.05	1.78
Production expense	**0.65**	0.63	0.57
Netback	**$ 4.39**	$ 3.58	$ 5.40
Barrels of oil equivalent ($/boe, except daily production)			
Daily production (boe/d)	**476,944**	455,935	455,952
Sales price (1)	**$ 35.88**	$ 30.43	$ 42.83
Royalties	**5.03**	4.12	6.96
Production expense	**7.02**	6.81	7.27
Netback	**$ 23.83**	$ 19.50	$ 28.60

(1) *Including transportation costs and excluding risk management activities.*

BUSINESS ENVIRONMENT

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
WTI benchmark price (US$/bbl)	**$ 35.16**	$ 31.18	$ 33.80
Dated Brent benchmark price (US$/bbl)	**$ 31.98**	$ 29.42	$ 31.47
Differential to LLB blend (US$/bbl)	**$ 9.92**	$ 10.39	$ 8.10
Condensate benchmark price (US$/bbl)	**$ 35.99**	$ 31.57	$ 33.30
NYMEX benchmark price (US$/mmbtu)	**$ 5.69**	$ 4.58	$ 6.64
AECO benchmark price (C$/GJ)	**$ 6.26**	$ 5.30	$ 7.53
US/Canadian dollar average exchange rate (US$)	**$ 0.76**	$ 0.76	$ 0.66

World crude oil prices strengthened in the first quarter of 2004 as a result of continued tight global supplies. Crude oil supplies have been impacted by the slower-than-expected pace of reconstruction in Iraq, continued unrest in Venezuela, the decision of the Organization of Petroleum Exporting Countries ("OPEC") for further quota reductions and rising worldwide demand. West Texas Intermediate ("WTI") averaged US$35.16 per bbl in the first quarter of 2004, up 4% compared to US$33.80 per bbl in the first quarter of 2003, and up 13% from US$31.18 per bbl in the prior quarter. The impact of the increase in the WTI price on the first quarter of 2004 was reduced as a result of wider heavy crude oil differentials, which increased 22% to US$9.92 per bbl from US$8.10 per bbl in the prior year, but decreased 5% from US$10.39 in the prior quarter. The Company's realized crude oil prices were also impacted by the higher costs associated with condensate that is used for blending with heavy crude oil. The increase in the condensate price resulted from additional bitumen supply caused by a major upgrader turnaround in the first quarter of 2004.

Natural gas prices remained strong due to concerns around supply. Natural gas prices decreased from the comparable period in the prior year but increased from the prior quarter. AECO natural gas prices decreased 17% to average $6.26 per GJ compared to $7.53 per GJ in the first quarter of 2003, but increased 18% compared to $5.30 per GJ in the prior quarter. NYMEX natural gas prices decreased 14% to average US$5.69 per mmbtu compared to US$6.64 per mmbtu in the first quarter of 2003, but increased 24% from US$4.58 per mmbtu in the prior quarter.

PRODUCT PRICES

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Crude oil and NGLs ($/bbl) [(1)]			
North America	**$ 30.72**	$ 25.17	$ 36.01
North Sea	**$ 44.27**	$ 41.70	$ 49.74
Offshore West Africa	**$ 42.08**	$ 36.42	$ 37.86
Company average	**$ 34.21**	$ 29.47	$ 39.37
Natural gas ($/mcf) [(1)]			
North America	**$ 6.37**	$ 5.35	$ 7.88
North Sea	**$ 5.08**	$ 3.32	$ 4.03
Offshore West Africa	**$ 4.80**	$ 3.95	$ 3.80
Company average	**$ 6.31**	$ 5.26	$ 7.75
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**52%**	48%	52%
Natural gas	**48%**	52%	48%

(1) *Including transportation costs and excluding risk management activities.*

Realized crude oil prices decreased 13% to average $34.21 per bbl for the three months ended March 31, 2004, down from $39.37 per bbl in the comparable period in 2003, primarily due to the impact of the strengthening Canadian dollar. The realized crude oil price increased 16% from the previous quarter price of $29.47 per bbl due mainly to higher world oil prices. The North America realized crude oil price for the first quarter was also impacted by wider heavy crude oil differentials and higher condensate premiums compared to the same period in the prior year. The North Sea realized crude oil price was impacted by a wider Brent differential to the WTI price in the first quarter of 2004. Offshore West Africa realized crude oil prices fluctuated due to changes to world oil prices.

The realized natural gas price decreased 19% to average $6.31 per mcf for the three months ended March 31, 2004, down from $7.75 per mcf in the comparable period in 2003, but increased 20% from $5.26 per mcf in the prior quarter due to supply and demand fundamentals. Natural gas prices decreased from the comparable period in the prior year due to the decrease in the North America benchmark natural gas price.

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

	Q1 2004	Q4 2003	Q1 2003
Canadian Natural's Wellhead Price[1]			
Light crude oil and NGLs (C$/bbl)	**$ 40.69**	$ 34.07	$ 44.82
Pelican Lake crude oil (C$/bbl)	**$ 29.93**	$ 24.05	$ 33.34
Primary heavy crude oil (C$/bbl)	**$ 27.17**	$ 21.49	$ 33.22
Thermal heavy crude oil (C$/bbl)	**$ 26.57**	$ 21.36	$ 31.25
Natural gas (C$/mcf)	**$ 6.37**	$ 5.35	$ 7.88

(1) *Including transportation costs and excluding risk management activities.*

DAILY PRODUCTION

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Crude oil and NGLs (bbl/d)			
North America	**192,151**	176,429	173,045
North Sea	**57,099**	54,529	56,963
Offshore West Africa	**12,036**	13,304	7,552
Total	**261,286**	244,262	237,560
Natural gas (mmcf/d)			
North America	**1,230**	1,206	1,265
North Sea	**54**	52	41
Offshore West Africa	**10**	12	4
Total	**1,294**	1,270	1,310
Product mix			
Light crude oil and NGLs	**25%**	25%	25%
Pelican Lake crude oil	**4%**	5%	5%
Primary heavy crude oil	**19%**	16%	13%
Thermal heavy crude oil	**7%**	8%	9%
Natural gas	**45%**	46%	48%

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Crude oil and NGLs (bbl/d)			
North America	**168,049**	155,063	149,988
North Sea	**57,020**	54,728	56,841
Offshore West Africa	**11,670**	12,926	7,312
Total	**236,739**	222,717	214,141
Natural gas (mmcf/d)			
North America	**966**	957	970
North Sea	**54**	52	41
Offshore West Africa	**9**	11	4
Total	**1,029**	1,020	1,015

Daily production and per barrel statistics are presented throughout the MD&A on a "before royalty" or "gross" basis. Production net of royalties is presented above for information purposes only.

Total crude oil and NGLs production before royalties increased 10% or 23,726 bbl/d from the comparable period in 2003 and 7% or 17,024 bbl/d from the prior quarter mainly due to the acquisition of Petrovera. Crude oil and NGLs production for the first quarter of 2004 was in line with the Company's guidance of 245,000 to 265,000 bbl/d previously provided.

Crude oil and NGLs production before royalties in North America increased 11% or 19,106 bbl/d from the comparable period in 2003 and increased 9% or 15,722 bbl/d from the prior quarter due to the acquisition of Petrovera.

Crude oil production before royalties from the North Sea was consistent with the comparable period in 2003 but increased 5% or 2,570 bbl/d from the previous quarter due to the timing of well workovers. In the first quarter of 2004, problems with a natural gas compressor used to create gas lift for optimizing crude oil production temporarily reduced production from the Murchison Field. In addition, the Murchison Field was shut down in mid-March for a planned maintenance program. In the first quarter of 2003, crude oil production from the North Sea was impacted by two unscheduled turnarounds on the Ninian South Platform, and well workovers in 2003 resulted in the Lyell field and the Columba B2 well being shut in for portions of the fourth quarter of 2003.

Offshore West Africa crude oil production before royalties increased 59% or 4,484 bbl/d from the comparable period in 2003 but decreased 10% or 1,268 bbl/d from the prior quarter. The increase in production from the prior year is due to the perforation of the upper zone of the East Espoir Field in the second quarter of 2003, and the completion of the fourth water injection well and two additional producing wells in 2003.

Overall, natural gas production before royalties in the first quarter was in line with the Company's guidance of 1,285 to 1,315 mmcf/d. Natural gas production continues to represent the Company's largest product offering and decreased 1% or 16 mmcf/d from the comparable period in 2003 as a result of normal production declines, but increased 2% or 24 mmcf/d from the prior quarter.

Natural gas production increased 2% or 24 mmcf/d from the prior quarter due to the acquisition of Petrovera and the focus on natural gas drilling. North America production was also impacted by unusual weather. Production from the Ladyfern Field in northeast British Columbia declined 39 mmcf/d to average 37 mmcf/d in the first quarter of 2004, down from an average of 76 mmcf/d in the first quarter of 2003 as well pressures continued to decline. In January, extreme cold weather resulted in well freeze-offs and field activity delays. Then unseasonably warm weather in February slowed down the movement of rigs and resulted in road bans. In addition, production of natural gas was impacted by the shut in of 11 mmcf/d of natural gas in the Athabasca Wabiskaw-McMurray oilsands area pursuant to the decision of the Alberta Energy and Utilities Board ("EUB") effective September 1, 2003. Based on the EUB Regional Geological Study, 5 mmcf/d of natural gas production previously shut in was brought back on production in 2004 and the Company estimates that an additional 11 mmcf/d of natural gas production may be at risk of being shut in. The preliminary EUB hearings concluded in April 2004 but no decision has been released by the EUB.

Natural gas production before royalties in the North Sea increased 32% or 13 mmcf/d from the comparable period in 2003 due to the increased working interests acquired in the Banff Field during 2003. Production of natural gas in the North Sea is expected to decline when the natural gas re-injection program on the Banff Field is implemented.

Natural gas production before royalties in Offshore West Africa increased 150% or 6 mmcf/d over the comparable period in 2003 due to the natural gas pipeline commencing operation in the third quarter of 2003.

The Company expects annual production levels before royalties to average 1,350 to 1,405 mmcf/d of natural gas and 265 to 283 mbbl/d of crude oil and NGLs in 2004. Second quarter 2004 production guidance before royalties is 1,427 to 1,455 mmcf/d of natural gas and 264 to 282 mbbl/d of crude oil and NGLs.

ROYALTIES

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Crude oil and NGLs ($/bbl)			
North America	**$ 3.85**	$ 3.05	$ 4.80
North Sea	**$ 0.06**	$ (0.15)	$ 0.11
Offshore West Africa	**$ 1.28**	$ 1.03	$ 1.20
Company average	**$ 2.91**	$ 2.22	$ 3.56
Natural gas ($/mcf)			
North America	**$ 1.33**	$ 1.10	$ 1.84
North Sea	**$ -**	$ -	$ -
Offshore West Africa	**$ 0.15**	$ 0.11	$ 0.11
Company average	**$ 1.27**	$ 1.05	$ 1.78
Company average ($/boe)	**$ 5.03**	$ 4.12	$ 6.96
Percentage of revenue (1)			
Crude oil and NGLs	**8%**	8%	9%
Natural gas	**20%**	20%	23%
Boe	**14%**	14%	16%

(1) *Including transportation costs and excluding risk management activities.*

North America crude oil and NGLs royalties fluctuated from both the prior quarter and the comparable prior year period as a result of fluctuations in benchmark oil prices.

North Sea crude oil royalties were eliminated effective January 1, 2003. The only royalty remaining in the North Sea is a gross overriding royalty on the Ninian Field. In the fourth quarter of 2003, the Company received a refund of royalties previously provided.

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

PRODUCTION EXPENSE

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Crude oil and NGLs ($/bbl)			
North America	**$ 8.65**	$ 8.43	$ 9.09
North Sea	**$ 13.26**	$ 13.42	$ 15.50
Offshore West Africa	**$ 7.09**	$ 6.67	$ 14.03
Company average	**$ 9.58**	$ 9.45	$ 10.79
Natural gas ($/mcf)			
North America	**$ 0.60**	$ 0.60	$ 0.55
North Sea	**$ 1.65**	$ 1.16	$ 1.09
Offshore West Africa	**$ 1.23**	$ 1.18	$ 2.37
Company average	**$ 0.65**	$ 0.63	$ 0.57
Company average ($/boe)	**$ 7.02**	$ 6.81	$ 7.27

North America crude oil and NGLs production expense for the three months ended March 31, 2004 decreased from the comparable period in 2003. The decrease was due to the impact of lower natural gas prices on the costs of fuel used in the generation of steam in the Company's thermal heavy crude oil operations. Conversely, first quarter 2004 production expense per barrel increased from the previous quarter due to increases in natural gas prices and the impact of extremely cold weather experienced early in 2004, resulting in the freeze up of some wells.

North Sea crude oil production varies on a per barrel basis from both the comparable period in 2003 and the prior quarter due to the timing of maintenance work and the changes in production volumes on a relatively fixed cost base. Production expense in the first quarter of 2003 was impacted by reduced production as a result of the shut down of the Ninian South Platform.

Offshore West Africa crude oil production costs are largely fixed in nature and therefore fluctuate on a per barrel basis from the comparable periods due to changes in production from the Espoir Field.

North America natural gas production expense per mcf for the three months ended March 31, 2004 increased from the comparable period in 2003 as a result of a general increase in service costs associated with increased industry activity and higher costs associated with colder weather experienced early in 2004.

MIDSTREAM ($ millions)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Revenue	**$ 16**	$ 16	$ 18
Production expense	**4**	4	5
Midstream cash flow	**12**	12	13
Depreciation	**2**	1	2
Segment earnings before taxes	**$ 10**	$ 11	$ 11

The Company's midstream assets consist of three crude oil pipeline systems and an 84-megawatt cogeneration plant at Primrose where the Company has a 50% working interest. Approximately 86% of the Company's heavy crude oil production was transported to the international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to transport its own production volumes at reduced costs compared to other transportation alternatives as well as earn third party revenue. This transportation control enhances the Company's ability to control the full range of costs associated with the development and marketing of its heavy crude oil.

Revenue from the midstream assets for the three months ended March 31, 2004 decreased from the comparable period in 2003 due to lower electricity prices received in 2004.

DEPLETION, DEPRECIATION AND AMORITIZATION (2)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003(1)	Mar 31 2003(1)
Expense ($ millions)	**$ 387**	$ 390	$ 359
$/boe	**$ 8.91**	$ 9.26	$ 8.75

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

(2) *Depletion, Depreciation and Amortization excludes depreciation on midstream assets.*

Depletion, Depreciation and Amortization ("DD&A") in the first quarter of 2004 increased in total and per boe from the prior year. The increase was due to higher finding and development costs associated with natural gas exploration in North America. DD&A decreased from the prior quarter on a per boe and total basis due to the write-off of the costs associated with the Company's exploration activity in offshore France in the fourth quarter of 2003.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended		
	Mar 31 2004	Dec 31 2003(1)	Mar 31 2003(1)
Expense ($ millions)	**$ 11**	$ 16	$ 15
$/boe	**$ 0.25**	$ 0.38	$ 0.37

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

Accretion expense is the increase in the carrying amount of the asset retirement obligation due to the passage of time.

ADMINISTRATION EXPENSE

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Net expense ($ millions)	$ **23**	$ 24	$ 18
$/boe	$ **0.54**	$ 0.58	$ 0.44

Administration expense for the three months ended March 31, 2004 increased in total and on a per boe basis from the comparable period in 2003 due to higher staffing levels associated with the Company's expanding asset base.

STOCK-BASED COMPENSATION

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Stock option plan ($ millions)	**$ 56**	$ 63	$ -
Share bonus plan ($ millions)	**$ 5**	$ -	$ -
Total Compensation expense ($ millions)	**$ 61**	$ 63	$ -
$/boe	**$ 1.41**	$ 1.50	$ -

The Company's Stock Option Plan (the "Option Plan") provides current employees, officers and directors (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The Option Plan balances the need for a long-term compensation program to retain employees with reducing the impact of dilution on current shareholders and the reporting of the expense associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are expensed. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The stock-based compensation expense relating to the Company's Option Plan for the three months ended March 31, 2004 is $56 million ($38 million after tax). The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings for the quarter.

The Share Bonus Plan incorporates share ownership in the Company by its employees without the granting of stock options or the dilution of current shareholders. Under the plan, a cash bonus, if awarded and based on the Company's and the employee's performance, is used by a trustee to acquire common shares of the Company. The common shares vest to the employee over a three-year period provided the employee does not leave the employment of the Company. If the employee leaves the employment of the Company, the unvested common shares are forfeited under the terms of the plan. For the period ended March 31, 2004, the Company has recognized $5 million ($3 million after tax) of compensation expense under the Share Bonus Plan.

The Company has recorded a liability at March 31, 2004 of $179 million (December 31, 2003 - $171 million; March 31, 2003 - nil) for expected cash settlements for stock-based compensation based on the intrinsic value of the outstanding stock options (the difference between the exercise price of the stock options and the market price of the Company's common shares). For the period ended March 31, 2004, the Company paid $35 million for stock options surrendered for cash settlement (December 31, 2003 - $31 million).

INTEREST EXPENSE

	Three Months Ended		
	Mar 31 2004	Dec 31 2003(1)	Mar 31 2003(1)
Interest expense, net ($ millions)	**$ 43**	$ 41	$ 57
$/boe	**$ 0.98**	$ 0.98	$ 1.38
Average effective interest rate	**5.6%**	5.6%	5.8%

(1) *The comparative figures for prior year have been reclassified to conform to the presentation adopted in 2004.*

Interest expense for the three months ended March 31, 2004 was impacted by the Company prospectively adopting the CICA Accounting Guideline 13, "Hedging Relationships" and EIC 128. As a result of the adoption of this accounting guideline, monies received on two of the fixed to floating interest rates swaps are included in risk management activities. The Company realized $9 million relating to the fixed to floating interest rates swaps in the first quarter of 2004, which has been excluded from interest expense and included in risk management activities.

RISK MANAGEMENT ACTIVITIES

On January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Financial instruments that do not qualify as hedges under the Guideline or are not designated as hedges are recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recognized in net earnings.

The Company utilizes various financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are not used for trading purposes.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The Company also enters into foreign currency denominated financial instruments to manage future US Dollar denominated crude oil and natural gas sales. Gains or losses on these contracts are included in risk management activity. The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principle amount on which the payments are based. Gains or loses on interest rate swap contracts designated as hedges are included in interest expense. Those contracts not designated as hedges are included in risk management activities. Gains or losses on the termination of financial instruments that have been accounted for as hedges are deferred under non-current assets or liabilities on the consolidated balance sheets and amortized in net earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized gain or loss is recognized in net earnings.

Adoption of this Guideline and EIC 128 had the following effects on the Company's financial statements for the three months ended March 31, 2004:

($ millions)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Realized (loss) gain			
Crude oil and NGLs financial instruments	**$ (37)**	$ 13	$ (88)
Natural gas collars financial instruments	**-**	(4)	(59)
Interest rate swaps	**9**	8	9
Total	**$ (28)**	$ 17	$ (138)
Unrealized (loss) gain			
Crude oil and NGLs financial instruments	**$ (106)**	$ -	$ -
Natural gas collars financial instruments	**(3)**	-	-
Interest rate swaps	**7**	-	-
Total	**$ (102)**	$ -	$ -
Total	**$ (130)**	$ 17	$ (138)

The effect of the realized loss (gain) on the Company's average realized prices was:

	Mar 31 2004	Dec 31 2003	Mar 31 2003
Crude oil and NGLs ($/bbl)	**$ 1.55**	$ (0.55)	$ 4.11
Natural gas ($/mcf)	**$ -**	$ 0.03	$ (0.50)

The effect of the realized gain on the Company's interest expense was:

($ millions)	**Mar 31 2004**	Dec 31 2003	Mar 31 2003
Interest expense as per the financial statements	**$ 43**	$ 41	$ 57
Realized risk management	**(9)**	(8)	(9)
	$ 34	$ 33	$ 48
Average effective interest rate	**4.4%**	4.5%	4.9%

Interest expense including realized risk management activities for the three months ended March 31, 2004 decreased from the comparable period in the prior year due to lower debt levels outstanding and lower average effective interest rates. Interest expense increased slightly from the prior quarter due to higher debt levels associated with the Petrovera acquisition and the Company's active capital expenditure program.

FOREIGN EXCHANGE ($ millions)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Realized foreign exchange (gain) loss	**$ (4)**	$ (6)	$ 1
Unrealized foreign exchange loss (gain)	**46**	(81)	(119)
	$ 42	$ (87)	$ (118)

The majority of the unrealized foreign exchange loss is related to the weakening Canadian dollar. The Canadian dollar ended the first quarter of 2004 at US$0.76 compared to US$0.77 at December 31, 2003 (March 31, 2003, US$0.63).

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

TAXES ($ millions, except income tax rates)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Taxes other than income tax			
Current	**$ 35**	$ 43	$ 25
Deferred	**4**	(17)	3
Total	**$ 39**	$ 26	$ 28
Current income tax			
North America – Current income tax	**$ 37**	$ 3	$ 16
North America – Large corporations tax	**3**	1	6
North Sea	**23**	2	15
Offshore West Africa	**3**	3	2
Total	**$ 66**	$ 9	$ 39
Future income tax (recovery) expense	**$ (18)**	$ 117	$ 227
Effective income tax rate	**15.6%**	33.6%	38.6%

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and provincial capital taxes. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after certain deductions including abandonment expenditures. Taxes other than income taxes increased from the comparable periods as a result of higher oil prices and increased production levels.

Taxable income from the conventional oil and natural gas business in Canada is generated by partnerships and the related income taxes will be payable in the following year. Current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary dependent upon the amount of capital expenditures incurred in Canada and the way it is deployed.

The Company is liable for the payment of Federal Large Corporations Tax ("LCT"). LCT decreased to $3 million or $0.08 per boe from $6 million or $0.13 per boe as a result of the Company being taxable and paying Federal corporate surtax. In addition, the LCT rate was reduced from 0.225% to 0.2% as part of the phased elimination of LCT over five years.

In the first quarter of 2004, the North America future tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate from 12.5% to 11.5%. The Federal Government also introduced legislation to reduce the corporate income tax rate on income from resource activities over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also provides for the elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid. As a result of these changes, the future income tax liability in North America was decreased by $247 million in 2003, which was recognized in the second quarter of 2003.

CAPITAL EXPENDITURES ($ millions)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Business Combination	**$ 471**	$ -	$ -
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 36**	$ 29	$ 178
Land acquisition and retention	**31**	44	21
Seismic evaluations	**32**	25	19
Well drilling, completion and equipping	**583**	352	396
Pipeline and production facilities	**280**	133	149
Total net reserve replacement expenditures	**$ 962**	$ 583	$ 763
Horizon Oil Sands Project	**46**	52	41
Midstream	**-**	2	3
Abandonments	**7**	20	3
Head office	**7**	5	3
Total net capital expenditures	**$ 1,022**	$ 662	$ 813
By segment			
North America	**$ 826**	$ 431	$ 643
North Sea	**76**	106	90
Offshore West Africa	**60**	46	30
Horizon Oil Sands Project	**46**	52	41
Midstream	**-**	2	3
Abandonments	**7**	20	3
Head office	**7**	5	3
Total	**$ 1,022**	$ 662	$ 813

The Company’s strategy is focused on building a diversified asset base that is balanced between various products. The capital expenditures program continues to reflect this strategy.

During the first quarter of 2004, capital expenditures were $1,022 million, excluding the acquisition of Petrovera, compared to $813 million in the first quarter of 2003. In the first quarter, the Company drilled a total of 839 net wells consisting of 358 natural gas wells, 143 crude oil wells, 268 stratigraphic test and service wells, and 70 wells that were dry and abandoned. The Company achieved an overall success rate of 88%.

North America accounted for 81% of the total capital expenditures in the first quarter compared to 79% in the comparable period in the prior year. In North America, capital expenditures were focused in the Company’s regions of North Alberta (312 net wells), Northeast British Columbia (176 net wells), Northwest Alberta (76 net wells) and South Alberta (77 net wells).

The first quarter included the drilling of 20 crude oil wells in the Company’s Pelican Lake area in North Alberta. These wells are part of the Company’s planned waterflood project. The waterflood project is being phased in and it is expected that approximately 20% of the Pelican Lake Field will be under waterflood by the end of 2004. It is expected that the waterflood will stabilize production and will require a further 63 productive wells to be converted from producers to water injectors and approximately 43 new wells to be drilled in 2004 as producers. The Company is also running a field pilot of a water / emulsion flood process and expects to have the results later this year. In the Primrose area in North Alberta, the Company completed the facilities on two pads drilled in 2003 and steaming on these pads began in early February with production expected mid-2004. In addition, the Company drilled 19 net high pressure horizontal thermal wells and plans to begin work on its 25,000 bbl/d plant extension, which will cost $250 million. The Company also drilled 76 primary heavy crude oil wells during the first quarter. The Company continues its exploration and development activities in the highly prospective core region of Northeast British Columbia where 173 net gas wells were drilled. In the Helmet area a total of 52 horizontal wells targeting Jean Marie natural gas zones were drilled, while in the Fort St. John Block, 86 Notikewin shallow wells and 4 deeper targets were drilled. In the Cardium-oriented southern portion of the Northwest Alberta core region, a total of 37 wells targeting natural gas were drilled with a success rate of 100%. Apart from Cardium drilling in this core region, a total of 38 wells targeting natural gas were drilled with a success rate of 79%. A total of 6 successful coal bed methane (“CBM”) targets were drilled during the quarter, principally in the South Alberta core region. These wells represent an initial testing of reserve potential on the Company’s lands. The Company is taking a cautious approach to CBM development and has not determined the aerial extent or resource potential of this test program. The Company was also active in its traditional natural gas core region of South Alberta where 77 wells targeting natural gas were drilled. In addition, 79 stratigraphic test wells were drilled on oil sands leases in North Alberta.

In the Horizon Oil Sands Project (“Horizon Project”), capital expenditures include work relating to the third front-end engineering phase, Engineering Design Specifications (“EDS”). The EDS is expected to be completed in the fall of 2004 and will provide sufficient definition for a lump-sum inquiry for the detailed Engineering, Procurement and Construction (“EPC”) of the various project components. The EDS will also provide a detailed cost estimate, and provide the basis upon which management can make a final recommendation to the Board of Directors for sanction of the Horizon Project. The first quarter of 2004 also included the drilling of 180 stratigraphic test wells on the oil sands leases of the Horizon Project. The Company received regulatory approvals from the Alberta Energy and Utilities Board as well as the Alberta Provincial Cabinet and the Federal Cabinet.

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

During the first quarter, the Company commenced development drilling of the Lyell Field from the Ninian Central Platform with one well being spudded late in the quarter. Increased production from this field is expected to flow late in the second quarter of 2004. A successful infill drilling program at the Ninian Field also continued with 4 wells drilled during the quarter.

Offshore West Africa capital expenditures included the continued development of the Baobab Field where fabrication of the Floating Production, Storage and Offtake Vessel and development drilling commenced in the fourth quarter of 2003. In addition, work continues on the development of the West Espoir Field.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003(1)	Mar 31 2003(1)
Working capital deficit (2)	**$ 923**	$ 505	$ 318
Long-term debt	**$ 3,061**	$ 2,645	$ 3,494
Shareholders' equity			
Preferred securities	**$ 104**	$ 103	$ 118
Share capital	**2,380**	2,353	2,327
Retained earnings	**3,881**	3,650	2,810
Foreign currency translation adjustment	**1**	3	16
Total	**$ 6,366**	$ 6,109	$ 5,271
Debt to cash flow (2) (3)	**1.0x**	0.9x	1.3x
Debt to EBITDA(2) (3)	**0.9x**	0.8x	1.1x
Debt to book capitalization(1) (2)	**33.7%**	31.6%	40.1%
Debt to market capitalization(2)	**24.7%**	24.2%	33.9%
After tax return on average common shareholders' equity(1) (2) (3)	**21.4%**	25.6%	20.3%
After tax return on average capital employed (1) (2) (3)	**14.6%**	16.7%	12.6%

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

(2) *Includes current portion of long term debt.*

(3) *Based in trailing 12-month activity.*

At March 31, 2004, the working capital deficit amounted to $923 million. The Company's capital expenditure program was en excess of $1 billion in the first quarter of 2004, an increase of $360 million over the fourth quarter of 2003 and $209 million over the first quarter of 2003. As the invoices are received, substantially in the second quarter of 2004, the liability will be extinguished. Similarly, the current portion of long-term debt due within the next 12 months of $178 million will be retired as the debt matures. The Company's current portion of other long-term liabilities of $257 million consists of stock based compensation of $153 million and the mark to market valuation of certain Risk Management financial derivative instruments of $104 million. The settlement of the stock-based compensation liability is dependant upon the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of exercise. The settlement of the Risk Management financial derivative instruments is primarily dependant upon the underlying crude oil and natural gas prices at the time of settlement of the financial derivative instrument, as compared to the value at March 31, 2004. At March 31, 2004 the Company had undrawn bank lines of credit of $1.267 billion.

The financing of the first phase of the Horizon Project development will be guided by the competing principles of retaining as much direct ownership interest as possible while maintaining current strong debt ratings and not issuing additional equity in common shares. The Company continues to investigate the use of long-term commodity hedges in order to reduce cash flow risks during the construction phase. The Company may also look to offload capital commitments through the acceptance of complementary business partners, or potentially, project joint venture partners. Recent commodity price increases have significantly strengthened the balance sheet of the Company, thereby placing it in a better position to achieve all three of its guiding principles.

Share Capital

The Company is authorized to issue an unlimited number of common shares. As at March 31, 2004, there were 134 million common shares outstanding. In addition, the Company, is authorized to issue 200,000 class 1 preferred shares. There were no preferred shares outstanding. As at April 29, 2004, the Company has 134,322,858 common shares outstanding.

In January 2004, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 6,690,385 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2004 and ending January 23, 2005. As at April 29, 2004, the Company had not purchased any additional shares using the renewed Normal Course Issuer Bid.

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

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

Subsequent Event

Subsequent to the quarter end, the Company completed the acquisition of certain resource properties producing approximately 68 mmcf/d located in Northeast British Columbia and Northwest Alberta for consideration of $280 million. The properties include a further ownership interest in the Ladyfern natural gas field, which complements the Company's existing holdings. The acquisition also provided over 415 thousand acres of developed and undeveloped land facilitating the expansion of existing Gething and Notikewin plays as well as an expanded presence in the Foothills areas of Alberta and British Columbia. These areas are characterized by large, high-rate deeper prospects and are considered higher risk / higher reward targets.

SENSITIVITY ANALYSIS (1)

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

	Cash flow from operations(2) ($ millions)	Cash flow from operations(2) (per common share, basic)	Net earnings(2) ($ millions)	Net earnings(2) (per common share, basic)
Price changes				
Oil – WTI US$1.00/bbl(3)				
Excluding financial derivatives	$ 96	$ 0.71	$ 68	$ 0.51
Including financial derivatives	$ 68-95	$ 0.50-0.71	$ 48-68	$ 0.36-0.51
Natural gas – AECO C$0.10/mcf(3)				
Excluding financial derivatives	$ 35	$ 0.26	$ 22	$ 0.16
Including financial derivatives	$ 35	$ 0.26	$ 21	$ 0.16
Volume changes				
Oil – 10,000 bbl/d	$ 63	$ 0.47	$ 27	$ 0.20
Natural gas – 10 mmcf/d	$ 16	$ 0.12	$ 7	$ 0.05
Foreign currency rate change				
$0.01 change in C$ in relation to US$(3)				
Excluding financial derivatives	$ 57	$ 0.42	$ 21	$ 0.15
Including financial derivatives	$ 51-54	$ 0.38-0.41	$ 17-20	$ 0.13-0.15
Interest rate change - 1%	$ 13	$ 0.10	$ 13	$ 0.10

(1) *The sensitivities are calculated based on 2004 first quarter results excluding mark-to-market on risk management activities.*
(2) *Attributable to common shareholders.*
(3) *For details of financial derivatives in place, see the consolidated financial statement note 11.*

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS
($/boe, except daily production)

	Three Months Ended		
	Mar 31 2004	Dec 31 2003	Mar 31 2003
Daily production (boe/d)	**476,944**	455,935	455,952
Sales price[1]	**$ 35.88**	$ 30.43	$ 42.83
Royalties	**5.03**	4.12	6.96
Production expense[2]	**7.02**	6.81	7.27
Netback	**23.83**	19.50	28.60
Midstream contribution[2]	**(0.27)**	(0.29)	(0.32)
Administration	**0.54**	0.58	0.44
Stock bonus plan	**0.11**	-	-
Interest	**0.98**	0.98	1.38
Risk management activities loss (gain) – realized	**0.64**	(0.40)	3.37
Foreign exchange (gain) loss – realized	**(0.09)**	(0.17)	0.02
Taxes other than income tax (current)	**0.82**	1.02	0.63
Current income tax (North America)	**0.86**	0.07	0.39
Current income tax (Large corporations tax)	**0.08**	0.01	0.13
Current income tax (North Sea)	**0.52**	0.07	0.37
Current income tax (Offshore West Africa)	**0.07**	0.07	0.05
Cash flow	**$ 19.57**	$ 17.56	$ 22.14

(1) *Including transportation costs.*

(2) *Excluding intersegment eliminations.*

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)		**March 31 2004**		December 31 2003[(1)]
ASSETS				
Current assets				
Cash	**$**	**26**	$	104
Accounts receivable and other		**985**		751
		1,011		855
Property, plant and equipment (net)		**14,947**		13,714
Deferred charges		**80**		74
	$	**16,038**	$	14,643
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**622**	$	464
Accrued liabilities		**877**		582
Current portion of long-term debt (note 4)		**178**		184
Current portion of other long-term liabilities (note 5)		**257**		130
		1,934		1,360
Long-term debt (note 4)		**3,061**		2,645
Other long-term liabilities (note 5)		**917**		938
Future income tax (note 6)		**3,760**		3,591
		9,672		8,534
SHAREHOLDERS' EQUITY				
Preferred securities		**104**		103
Share capital (note 7)		**2,380**		2,353
Retained earnings		**3,881**		3,650
Foreign currency translation adjustment (note 8)		**1**		3
		6,366		6,109
	$	**16,038**	$	14,643

(1) *Restated (note 2)*

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended March 31 2004	2003[1]
Revenue	**$ 1,638**	$ 1,840
Less: royalties	**(218)**	(286)
Revenue, net of royalties	**1,420**	1,554
Expenses		
Production	**308**	303
Transportation	**66**	65
Depletion, depreciation and amortization	**389**	361
Asset retirement obligation accretion (note 5)	**11**	15
Administration	**23**	18
Stock-based compensation (note 5)	**61**	-
Interest	**43**	57
Risk management activities	**130**	138
Foreign exchange loss (gain)	**42**	(118)
	1,073	839
Earnings before taxes	**347**	715
Taxes other than income tax	**39**	28
Current income tax (note 6)	**66**	39
Future income tax (recovery) expense (note 6)	**(18)**	227
Net earnings	**260**	421
Dividend on preferred securities, net of tax	**(1)**	(1)
Revaluation of preferred securities, net of tax	**(1)**	7
Net earnings attributable to common shareholders	**$ 258**	$ 427
Net earnings attributable to common shareholders per common share (note 9)		
Basic	**$ 1.92**	$ 3.19
Diluted	**$ 1.92**	$ 3.03

(1) *Restated (note 2)*

Consolidated statements of retained earnings

	Three Months Ended March 31			
(millions of Canadian dollars, unaudited)		**2004**		2003(1)
Balance – beginning of period as previously reported	**$**	**3,644**	$	2,414
Change in accounting policy (note 2)		**6**		10
Balance – beginning of period as restated		**3,650**		2,424
Net earnings		**260**		421
Dividend on common shares (note 7)		**(27)**		(20)
Purchase of common shares (note 7)		**-**		(21)
Dividend on preferred securities, net of tax		**(1)**		(1)
Revaluation of preferred securities, net of tax		**(1)**		7
Balance – end of period	**$**	**3,881**	$	2,810

(1) *Restated (note 2)*

Consolidated statements of cash flows

	Three Months Ended March 31	
(millions of Canadian dollars, unaudited)	**2004**	2003[1]
Operating activities		
Net earnings	**$ 260**	$ 421
Non-cash items		
Depletion, depreciation and amortization	**389**	361
Asset retirement obligation accretion	**11**	15
Stock-based compensation	**56**	-
Deferred petroleum revenue tax	**4**	3
Unrealized risk management activities	**102**	-
Future income tax (recovery)	**(18)**	227
Unrealized foreign exchange loss (gain)	**46**	(119)
Cash flow provided from operations	**850**	908
Deferred charges	**(6)**	5
Cash settlement of stock options	**(35)**	-
Abandonment expenditures	**(7)**	(3)
Net change in non-cash working capital	**(117)**	(82)
	685	828
Financing activities		
Issue (repayment) of bank credit facilities	**383**	(372)
Repayment of obligations under capital leases	**(6)**	(5)
Issue of common shares	**12**	34
Purchase of common shares	**-**	(32)
Dividend on common shares	**(20)**	(17)
Dividend on preferred securities	**(2)**	(2)
Net change in non-cash working capital	**(9)**	2
	358	(392)
Investing activities		
Business combinations, net of cash acquired (note 3)	**(444)**	-
Expenditures on property, plant and equipment	**(1,017)**	(817)
Net proceeds on sale of property, plant and equipment	**2**	7
Net expenditures on property, plant and equipment	**(1,459)**	(810)
Net change in non-cash working capital	**338**	361
	(1,121)	(449)
Decrease in cash	**(78)**	(13)
Cash – beginning of period	**104**	30
Cash – end of period	**$ 26**	$ 17

(1) *Restated (note 2)*

Supplemental disclosure of cash flow information (note 10)

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

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2003, except as described in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2003.

Comparative figures

Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2004.

2. CHANGES IN ACCOUNTING POLICIES

Asset retirement obligation

Effective January 1, 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountants' ("CICA") new Handbook Section 3110, "Asset Retirement Obligations". The Section requires the recognition of the fair value of the asset retirement obligation for related long-term assets as a liability. Retirement costs equal to the discounted retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows. Previously, future site restoration costs were accrued over the life of the Company's proved reserves. This new standard was adopted retroactively and prior period comparative balances have been restated. Adoption of the standard had the following effects on the Company's consolidated balance sheet as at December 31, 2003:

		Dec 31, 2003
Increase property, plant and equipment	$	445
Decrease future site restoration liability	$	(447)
Increase asset retirement obligation	$	897
Increase future income tax liability	$	3
Decrease foreign currency translation adjustment	$	(14)
Increase retained earnings	$	6

Adoption of the standard had the following effects on the Company's consolidated statements of earnings and retained earnings:

	Three Months Ended			
	Mar 31, 2004		Mar 31, 2003	
Increase opening retained earnings	**$**	**6**	$	10
Decrease depletion, depreciation and amortization	**$**	**(24)**	$	(14)
Increase asset retirement obligation accretion	**$**	**11**	$	15
Decrease future income tax expense	**$**	**(5)**	$	-

Risk Management

Effective January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Guideline 13 addresses the types of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting, and the requirement to evaluate hedges for effectiveness. EIC 128 requires that financial instruments that are not designated as hedges be recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recorded in earnings. The Company has not designated its derivative financial instruments (note 11) as hedges, with the exception of the currency swap on the US$125 million senior unsecured note and the interest rate swap on the US$350 million note due October 2012. Adoption of Guideline 13 and EIC 128 had the following effects on the Company's consolidated balance sheet as at January 1, 2004:

		Jan 1, 2004
Increase financial instruments asset	$	40
Increase deferred revenue	$	40

The deferred revenue will be amortized to earnings over the term of the underlying contracts.

3. ACQUISITION OF PETROVERA PARTNERSHIP

In February 2004, the Company acquired certain resource properties in its North Alberta core region, collectively known as the Petrovera Partnership ("Petrovera"), for $471 million.

The acquisition was accounted for based on the purchase method. Results from Petrovera are consolidated with the results of the Company effective from the date of acquisition. The preliminary allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

		Feb 2004
Purchase price		
Cash consideration	$	467
Cash acquired		(23)
Non-cash working capital deficit assumed		27
Total purchase price	$	471

Net assets acquired:		
Property, plant and equipment	$	645
Future income tax liability		(131)
Asset retirement obligation		(43)
Total net assets acquired	$	471

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 the actual amounts are determined.

4. LONG-TERM DEBT

	Mar 31 2004	Dec 31 2003
Bank credit facilities		
Bankers' acceptances	**$ 365**	$ -
US dollar bankers' acceptances (2004 – US$221 million, 2003 – US$207 million)	**289**	268
Medium-term notes	**250**	250
Senior unsecured notes (2004 – US$258 million, 2003 – US$258 million)	**368**	366
US dollar debt securities (2004 – US$1,500 million, 2003 – US$1,500 million)	**1,966**	1,938
Obligations under capital leases	**1**	7
	3,239	2,829
Less: current portion of long-term debt	**178**	184
	$ 3,061	$ 2,645

Bank credit facilities

At March 31, 2004, the Company had unsecured bank credit facilities of $1,925 million comprised of a $100 million operating demand facility and a revolving credit and term loan facility of $1,825 million.

In addition to the outstanding debt, letters of credit aggregating $12 million have been issued.

5. OTHER LONG-TERM LIABILITIES

	Mar 31 2004	Dec 31 2003
Asset retirement obligation	**$ 893**	$ 897
Stock-based compensation	**179**	171
Risk management	**58**	-
Deferred revenue	**44**	-
	1,174	1,068
Less: current portion	**257**	130
	$ 917	$ 938

Asset retirement obligation

At March 31, 2004, the Company's total estimated undiscounted costs to settle its asset retirement obligation with respect to oil and natural gas properties and facilities was $ 2,531 million (December 31, 2003 – $2,281 million, March 31, 2003 – $ 1,984 million). These costs will be incurred over several years and have been discounted using a credit-adjusted risk free rate of 6.7%. A reconciliation of the discounted asset retirement obligation is as follows:

	Three months ended Mar 31, 2004	Year ended Dec 31, 2003(1)
Asset retirement obligation		
Balance – beginning of period	**$ 897**	$ 867
Liabilities incurred	**47**	117
Liabilities settled	**(7)**	(40)
Asset retirement obligation accretion	**11**	62
Revision of estimates	**(62)**	(6)
Foreign exchange	**7**	(103)
Balance – end of period	**$ 893**	$ 897

(1) *Effective January 1, 2004 the Company retroactively adopted CICA handbook section 3110, "Asset Retirement Obligations" (note 2). Prior period balance of other long-term liabilities have been restated.*

The Company's pipelines and co-generation plant have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligation for these assets will be recorded in the year in which the lives of the assets are determinable.

Stock-based compensation

The Company's Stock Option Plan ("Option Plan") results in the recognition of a liability for the expected cash settlements under the Option Plan. The current portion represents the amount of the liability that could be realized within the next 12 month period if all vested options are surrendered for cash settlement.

	Three months ended Mar 31, 2004	Year ended Dec 31, 2003
Stock-based compensation		
Balance – beginning of period	**$ 171**	**$** -
Stock-based compensation provision	**61**	200
Current period expense relating to Stock Option bonus plan	**(5)**	-
Current period payment for options surrendered	**(35)**	(31)
Transferred to common shares	**(15)**	(8)
Capitalized with respect to Horizon Project	**2**	10
Balance – end of period	**179**	171
Less: current portion	**153**	130
	$ 26	**$** 41

Risk Management

On January 1, 2004, the fair values of all outstanding financial instruments that are not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount (note 2). The deferred revenue will be amortized to net earnings over the term of the underlying contracts. Subsequent changes in fair value are recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all financial instruments is based on third party indications. The following table reconciles the change in derivative financial instruments:

Liability (asset)	Deferred Revenue	Risk Management Mark-to-market
Fair value of financial instruments – Jan 1, 2004	$ 40	$ (40)
Change in fair value of financial instruments	-	98
Amortization of deferred revenue	4	-
Fair value of financial instruments – Mar 31, 2004	44	58
Less current portion	24	80
	$ 20	$ (22)

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended Mar 31	
	2004	2003
Current income tax expense		
Current income tax – North America	$ 37	$ 16
Large corporations tax – North America	3	6
Current income tax – North Sea	23	15
Current income tax – Offshore West Africa	3	2
	66	39
Future income tax (recovery) expense	(18)	227
Income taxes	$ 48	$ 266

A significant portion of the Company's North American taxable income is generated by partnerships. Income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings. Current income tax will vary and is dependant upon the amount of capital expenditures incurred in Canada and the way it is deployed.

In March 2004, the Government of Alberta introduced legislation to reduce its corporate income tax rate by 1% effective April 1, 2004. The change is considered substantively enacted for the purposes of Canadian GAAP and accordingly, the Company's future income tax liability was reduced by $66 million in the quarter.

7. SHARE CAPITAL

Issued

Common shares	Mar 31, 2004 Number of shares (thousands)		Amount
Balance – beginning of period	**133,731**	**$**	**2,353**
Issued upon exercise of stock options	**380**		**12**
Previously recognized liability on stock options exercised for common shares	**-**		**15**
Balance – end of period	**134,111**	**$**	**2,380**

Normal course issuer bid

On January 22, 2004, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,690,385 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 24, 2004 and ending January 23, 2005. As at March 31, 2004, the Company had not purchased any shares under its renewed Normal Course Issuer Bid.

Dividend policy

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

Stock options

	Mar 31, 2004 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**8,894**	**$**	**39.44**
Granted	**1,836**	**$**	**67.90**
Exercised for common shares	**(380)**	**$**	**31.70**
Surrendered for cash settlement	**(1,016)**	**$**	**35.78**
Forfeited	**(116)**	**$**	**44.09**
Outstanding – end of period	**9,218**	**$**	**45.77**
Exercisable – end of period	**2,119**	**$**	**36.11**

8. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. The Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, gains and losses on this debt are included in the foreign currency translation adjustment.

	Mar 31, 2004
Balance – beginning of period as previously reported	**$ 17**
Change in accounting policy (note 2)	**(14)**
Balance – beginning of period as restated	**3**
Unrealized loss on translation of net investment	**5**
Hedge of net investment with US dollar denominated debt (net of tax)	**(7)**
Balance – end of period	**$ 1**

9. NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS PER COMMON SHARE

	Three Months Ended Mar 31	
	2004	2003
Weighted average common shares outstanding (thousands)		
Basic	**134,085**	134,036
Effect of dilutive stock options (1)	**-**	2,668
Assumed settlement of preferred securities with common shares	**1,491**	2,420
Diluted	**135,576**	139,124
Net earnings attributable to common shareholders	**$ 258**	$ 428
Dividend on preferred securities, net of tax	**1**	1
Revaluation of preferred securities, net of tax	**1**	(7)
Diluted net earnings attributable to common shareholders	**$ 260**	$ 422
Net earnings attributable to common shareholders per common share		
Basic	**$ 1.92**	$ 3.19
Diluted	**$ 1.92**	$ 3.03

(1) *As a result of the modification of the Option Plan in June 2003, which resulted in the recognition of a liability and expense for all outstanding stock options, the potential common shares associated with the stock options are not included in diluted earnings per share effective from the date of the modification.*

10. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended Mar 31	
	2004	2003
Interest paid	**$ 49**	$ 42
Taxes paid (recovered)	**$ 67**	$ (7)

11. 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 April 29, 2004 which includes all transactions outstanding at March 31, 2004

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps	Apr 2004 – Dec 2004	40,000 bbl/d	US$1.22	Dated Brent/WTI
Oil price collars	Apr 2004 – Jun 2004	120,000 bbl/d	US$25.06 – US$29.84	WTI
	Jul 2004 – Sep 2004	120,000 bbl/d	US$25.63 – US$30.40	WTI
	Oct 2004 – Dec 2004	120,000 bbl/d	US$26.25 – US$33.34	WTI
	Jan 2005 – Mar 2005	50,000 bbl/d	US$27.00 – US$34.36	WTI

	Remaining Term	Volume	Average Price	Index
Natural gas				
AECO collars	Apr 2004 – Oct 2004	400,000 GJ/d	C$5.00 – C$8.76	AECO

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

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

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

12. SEGMENTED INFORMATION

	Three Months Ended Mar 31	
	2004	2003
Revenue		
North America	**$ 1,318**	$ 1,528
North Sea	**263**	276
Offshore West Africa	**50**	27
Midstream	**16**	18
Intersegment elimination	**(9)**	(9)
	$ 1,638	$ 1,840
Net Earnings		
North America	**$ 215**	$ 361
North Sea	**26**	50
Offshore West Africa	**13**	4
Midstream	**6**	6
	260	421
Dividend on preferred securities, net of tax	**(1)**	(1)
Revaluation of preferred securities, net of tax	**(1)**	7
Net Earnings Attributable to Common Shareholders	**$ 258**	$ 427
Additions to Property, Plant and Equipment		
North America – business combination	**$ 645**	$ -
North America – oil and natural gas	**826**	643
North Sea	**76**	107
Offshore West Africa	**60**	30
Horizon Oil Sands Project	**46**	41
Midstream	**-**	3
Abandonments	**7**	3
Head office	**7**	3
	$ 1,667	$ 830

	Property, Plant and Equipment		Total Assets	
	Mar 31 2004	Dec 31 2003	**Mar 31 2004**	Dec 31 2003
Segmented Assets				
North America	**$ 12,152**	$ 10,990	**$ 12,990**	$ 11,731
North Sea	**1,415**	1,437	**1,595**	1,562
Offshore West Africa	**712**	667	**750**	703
Horizon Oil Sands Project	**427**	381	**427**	381
Midstream	**198**	200	**233**	227
Head office	**43**	39	**43**	39
	$ 14,947	$ 13,714	**$ 16,038**	$ 14,643

13. SUBSEQUENT EVENT

Subsequent to the quarter end, the Company completed the acquisition of certain resource properties producing approximately 68 mmcf/d located in Northeast British Columbia and Northwest Alberta for consideration of $280 million. The properties include a further ownership interest in the Ladyfern natural gas field, which complements the Company's existing holdings. The acquisition also provided over 415 thousand acres of developed and undeveloped land facilitating the expansion of existing Gething and Notikewin plays as well as an expanded presence in the Foothills areas of Alberta and British Columbia.

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated August 2003. These ratios are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the 12-month period ended March 31, 2004:	
Interest coverage (times)	
Net earnings	10.5 (1)
Cash flow from operations	22.2 (2)

(1) *Net earnings plus income taxes and interest expense; divided by interest expense.*

(2) *Cash flow from operations 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 March 31, 2004, would be 10.0x and the cash flow coverage ratio for the 12-month period ended March 31, 2004 would be 21.0x.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time, on Wednesday, May 5, 2004. The North American conference call number is 1-800-840-6238 and the outside North America conference call number is 1-416-641-6661. Please call in about 10 minutes before the starting time in order to be patched into the call. Should you experience any difficulty in connecting to the call, those in North America please call 1-800-473-0602; and for those outside North America, please call 1-905-502-3723. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural Resources website at www.cnrl.com.

A taped rebroadcast will be available until 11:00 p.m. Mountain Daylight Time on Wednesday, May 12, 2004. To access the postview in North America, dial 1-800-558-5253 and enter the reservation number 21192470. Those outside North America, dial 1-416-626-4100 and enter the passcode 21192470.

WEBCAST

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

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

2004 SECOND QUARTER RESULTS

2004 second quarter results are scheduled for release on Wednesday, August 4, 2004. A conference call will be held on that day at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

ANNUAL GENERAL MEETING

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

For further information, please contact:

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