

Q3
Nine Months Ended
September 30, 2004

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY CASH FLOW IN EXCESS OF ONE BILLION DOLLARS AS WELL AS RECORD PRODUCTION AND CASH FLOW FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2004

In commenting on third quarter 2004 results, Canadian Natural's Chairman, Allan Markin, stated "This was yet another milestone quarter for Canadian Natural as we continue to execute our defined growth plan, achieving record results. We have again set quarterly records for crude oil production and cash flow from operations and I believe that with our asset base, our strong track record of profitable growth is set to continue."

"Long-term growth prospects for the Company are enhanced as we move closer to sanction of the Horizon Oil Sands Project. The complexity of this Project is exacerbated by the current environment in which labour and steel prices, to name two, are encountering a great deal of demand. As a result we now expect total Project costs of approximately $9.7 billion with a contingent estimated risked cost of $10.5 billion for the three phases of the development. Our Management and Board of Directors will not compromise on our financial discipline and mission statement beliefs and in order to 'do it right' we will only move forward on the Horizon Oil Sands Project when we are comfortable with our cost estimates and as such, the Company is continuing to gather additional data for the Project in order to make the best decision for our Company and Shareholders. In the interim, work continues and we see no change to our commissioning dates."

Canadian Natural's President, John Langille, in commenting on the financial results of the third quarter stated "Continued exploitation and opportunistic acquisitions in our conventional business carried us to new highs, achieving quarterly cash flow in excess of $1 billion. Our earnings for the third quarter represent an increase of 20% over the second quarter of 2004. The Company continues to create long-term value for its Shareholders."

Canadian Natural's Chief Operating Officer, Steve Laut, in commenting on the year ahead stated "We are very proud of our achievements to date and are excited about the opportunities that exist for Canadian Natural in 2005 as well as in the mid- and long-term. Horizon is approaching the point in time when the Board of Directors can make an informed decision and with Baobab, Primrose and the upside potential from our acquisitions this year the Company has never had a stronger inventory of projects."

HIGHLIGHTS OF THE THIRD QUARTER

- Record quarterly crude oil and NGLs production of 297 mbbl/d before royalties (270 mbbl/d net of royalties). This represents an increase of 8% over Q2/2004 production and 20% over Q3/2003 production.

- Quarterly natural gas sales of 1,396 mmcf/d before royalties (1,091 mmcf/d net of royalties), representing 44% of equivalent production during the quarter. This represents a decrease of 4% over Q2/2004 production and an 8% increase over Q3/2003 production.

- Record quarterly equivalent production of 530 mboe/d before royalties (451 mboe/d net of royalties), representing the fourth consecutive quarter of overall production growth, a 2% increase from Q2/2004 and a 15% increase over Q3/2003.

- Record quarterly cash flow of $1,041 million ($3.88 per common share) compared with $758 million ($2.81 per common share) in Q3/2003 and $930 million ($3.47 per common share) in Q2/2004.

- Net earnings of $311 million ($1.16 per common share) compared with $201 million ($0.75 per common share) for Q3/2003 and $259 million ($0.97 per common share) in Q2/2004. Adjusted net earnings from operations, a non Generally Accepted Accounting Principle ("GAAP") term used by the Company to judge its operational performance, amounted to $381 million ($1.42 per common share) compared with $213 million ($0.79 per common share) for Q3/2003 and $364 million ($1.36 per common share) in Q2/2004.

- Completed the acquisition of light crude oil producing properties in the Central North Sea, adding approximately 16,000 boe/d of production to the Company's production base.

- Capital expenditures of $875 million, reflecting third quarter drilling activities and the previously noted Central North Sea property acquisition. During the quarter, Canadian Natural drilled 145 wells with a 93% success ratio.

- Filed a public disclosure document for regulatory approval of the Primrose East project which is expected to boost production by 30 mbbl/d of bitumen by 2009.

- Maintained the quarterly dividend of $0.10 per common share for the October 1, 2004 payment.

- Continued with the repurchase of 73,400 common shares under its Normal Course Issuer Bid.

- Debt to book capitalization at the end of the third quarter was 33%. In the current pricing environment, debt to book capitalization will stay strong through the end of 2004.

- Canadian Natural is pleased to announce that the Honourable Frank McKenna, P.C., O.N.B., Q.C., has been appointed a member of the Board of Directors of the Company. Mr. McKenna, the former Premier of the Province of New Brunswick, is currently counsel with the Atlantic law firm of McInnes Cooper.

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 operational performance and that of its business segments.

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Net earnings attributable to common shareholders as reported	**$ 311**	$ 259	$ 201	**$ 828**	$ 1,153
Unrealized foreign exchange (gain) loss[1]	**(80)**	28	(9)	**(14)**	(206)
Unrealized risk management activities[2]	**70**	47	-	**185**	-
Effect of statutory tax rate changes on future income tax liabilities[3]	**-**	-	-	**(66)**	(247)
Stock-based compensation expense[4]	**80**	30	21	**151**	93
Adjusted net earnings from operations attributable to common shareholders	**$ 381**	$ 364	$ 213	**$ 1,084**	$ 793
Per share – basic[5]	**$ 1.42**	$ 1.36	$ 0.79	**$ 4.04**	$ 2.95
– diluted[5]	**$ 1.41**	$ 1.36	$ 0.78	**$ 4.02**	$ 2.89

(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. Also during 2003, a Canadian Province introduced legislation to reduce its corporate income tax rate.

(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, net of taxes, flow through earnings.

(5) Restated to reflect two-for-one share split in May 2004.

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

Total production for the third quarter of 2004 represents an increase of 15% over Q3/2003 and 2% increase over Q2/2004.

Total natural gas production increased 8% over the previous year, while average North American natural gas production levels in Q3/2004 represented an increase of 9% over the previous year. This strong growth is comprised of approximately 5% organic growth with the remainder being comprised of property acquisitions. As expected, third quarter production decreases from Q2/2004 reflect seasonality caused by a first quarter emphasis on drilling natural gas in winter-access only areas compared with significantly smaller spring and summer drilling programs.

Record average crude oil and NGLs production during Q3/2004 totalled 297 mbbl/d. This represents an 8% increase over Q2/2004 and a 20% increase over Q3/2003, reflecting drilling successes and accretive acquisitions.

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

	Q3 2004		Q2 2004		Q3 2003	
	mboe/d	%	mboe/d	%	mboe/d	%
Natural gas	**232.7**	**44**	241.9	47	214.9	46
Light crude oil and NGLs	**128.8**	**24**	118.7	23	118.9	26
Pelican Lake crude oil	**21.0**	**4**	19.6	4	23.5	5
Primary heavy crude oil	**96.3**	**18**	101.4	19	68.3	15
Thermal heavy crude oil	**51.1**	**10**	35.7	7	36.3	8
Total	**529.9**	**100**	517.3	100	461.9	100

The Company currently expects 2004 production levels before royalties to average 1,371 to 1,383 mmcf/d of natural gas and 279 to 288 mbbl/d of crude oil and NGLs. Fourth quarter 2004 production guidance before royalties for natural gas is 1,350 to 1,385 mmcf/d of natural gas and 291 to 311 mbbl/d of crude oil and NGLs. Detailed guidance on production levels and operating costs can be found on the Company's website (www.cnrl.com/investor_info/corporate_guidance.html).

Drilling Activity (number of wells)

	Nine months ended Sep 30, 2004			
	2004		2003	
	Gross	**Net**	Gross	Net
Crude oil	**249**	**221**	390	366
Natural gas	**607**	**537**	616	577
Dry	**88**	**82**	44	41
Subtotal	**944**	**840**	1,050	984
Stratigraphic test / service wells	**277**	**276**	378	374
Total	**1,221**	**1,116**	1,428	1,358
Success rate (excluding strat test / service wells)		**90%**		96%

During the quarter, Canadian Natural drilled 145 net wells, including 6 stratigraphic test and service wells. As much of Canadian Natural's natural gas regions are winter-access only, the Company's natural gas drilling is concentrated in the winter months. Hence the third quarter is typified by declines from second quarter peak production levels and a significant reduction in drilling activity. The spring and summer drilling program is typically comprised of heavy crude oil drilling as well as shallow natural gas drilling in South Alberta.

During the third quarter, Canadian Natural drilled 99 net wells targeting natural gas, including 26 wells in North Alberta and 19 wells in Northwest Alberta. A total of 43 shallow natural gas wells were drilled in South Alberta during the quarter. This compares with 196 such wells drilled in the same period of 2003. This program reflected both delays due to wetter than normal weather and an intentional reduction as part of the capital reallocations implemented in response to property acquisitions made earlier in the year. The drilling locations originally selected for this region form part of the larger project portfolio and will be drilled at a later date.

The Company also drilled 36 net wells targeting crude oil during the third quarter 2004. These wells were concentrated in the Company's crude oil region of North Alberta where 22 wells targeting primary heavy crude oil were drilled. Also drilled during the quarter were 14 high-pressure thermal crude oil wells that were drilled and completed at Primrose as part of the 2004 development strategy for the area.

The total success rate for Canadian Natural's drilling program was 93% for the quarter and 90% for the first nine months, 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 its asset base.

For the fourth quarter, Canadian Natural has shifted capital spending levels to reduce pressures of a tight winter drilling season by starting earlier. This effort includes the most detailed and organized drilling program in the Company's history and also ensures the procurement of better drilling rigs and crews for the winter season, both of which are an integral part of cost control in an inflationary environment.

Pricing

Detailed reviews of benchmark pricing and sensitivity to product pricing, currency exchange, and interest rates are provided in Management's Discussion and Analysis. Overall, product pricing for both crude oil and natural gas increased during Q3/2004 when compared to either Q2/2004 or Q3/2003. Heavy crude oil differentials increased 8% to US$12.55 in Q3/2004 reflecting higher light crude oil prices. The long-term heavy crude oil differential has approximated 30% of WTI benchmark price over a long period of time and during the third quarter, averaged 29% of the WTI benchmark price compared to 30% in Q2/2004 and 29% in Q3/2003. Another major determinant in heavy oil price realizations is cost of diluent required to increase viscosity of the production to meet requirements for transmission in sales pipelines. On a positive note, the cost of acquiring this diluent decreased from the second quarter of 2004, more than offsetting the absolute dollar impact of higher heavy oil differentials, resulting in higher heavy oil price realizations. Current indications are that heavy oil differentials will widen, when expressed as a percentage of WTI, and that diluent costs will increase, both from third quarter levels, with the result that fourth quarter heavy oil price realizations could decrease by up to 10%. This reflects normal seasonality of lower demand for heavy oil during winter months as well as greater supplies of heavy oil on world markets. However, price netbacks remain very robust on a historical basis and continue to support exceptionally high recycle ratios.

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 55 mbbl/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, and will continue to moderate pressure on traditional diluent costs. As part of an industry initiative to develop new blends of western Canadian crude oils, Canadian Natural, effective December 1, 2004 has capacity to blend up to 140 mbbl/d of Synbit and other crude oil blends. In addition to the Synbit strategy, a portion of this capacity will be dedicated to the Western Canadian Select ("WCS") stream, a new blend of up to 10 different crude oil streams from several different crude producers. WCS resembles a Bow River type of crude with distillation cuts approximating a natural heavy oil with premium quality asphalt characteristics. The new blend will have an API of 19-22 degrees. There is potential for the new blend to become a new benchmark for North American markets, in addition to WTI (West Texas Intermediate), representing a stream that is growing in size. Both current key benchmarks recognized by the market, WTI and Brent (North Sea) are showing significant declines in quantity. This could also enhance the Company's ability to directly financially hedge its product mix.

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, cost-less collars and puts are utilized against benchmark commodity prices as well as currency exposures. The details of these financial 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 not designated as hedges for accounting purposes. These amounts represent valuations at the balance sheet date had the Company monetized 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 valuation are discussed and detailed in Management's Discussion and Analysis.

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at Sep 30, 2004	Drilling Activity Nine months ended Sep 30, 2004
	(thousands of net acres)	(net wells)
Northeast British Columbia	**1,868**	**180**
Northwest Alberta	**1,614**	**108**
North Alberta	**6,538**	**445**
South Alberta	**662**	**180**
Southeast Saskatchewan	**124**	**11**
Horizon Oil Sands Project	**117**	**180**
United Kingdom North Sea	**608**	**10**
Offshore West Africa	**940**	**2**
	12,471	**1,116**

North American Natural Gas

Canadian Natural's North American natural gas production and development is focused in four core regions in which the Company dominates the land base and infrastructure. Production during the third quarter was within guidance levels and averaged 1,336 mmcf/d, an increase of 9% or 107 mmcf/d from Q3/2003 and, as expected, a decrease of 4% or 53 mmcf/d from Q2/2004. Approximately half of the increase from the prior year reflects organic growth with the remainder representing accretive property acquisitions.

The decrease in the third quarter from Q2/2004 production was expected and reflects the seasonality of drilling in the basin. Since the majority of the Company's natural gas drilling occurs in the winter months, the second quarter generally benefits from peak production levels. Although drilling continues in the third and fourth quarters it is generally not sufficient to offset normal production declines. This seasonality was further magnified by a wetter than normal summer in which it became difficult to efficiently drill and complete wells.

North American Crude Oil and NGLs

Canadian Natural's North American crude oil and NGLs production averaged a record 214 mbbl/d up 5% from Q2/2004 and 23% from Q3/2003. These record results were attributable to results that exceeded expectations from the new phases of the Primrose South in-situ thermal crude oil facility and accretive acquisitions. Canadian Natural continues the development of its vast heavy crude oil resources. As has been previously articulated, the development of these assets will be brought on stream as the demand for heavy crude oil markets permit. In addition to the potential expansion of markets for Synbit and WCS, the Company is working with refiners to advance expansions of 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 can 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. During the third quarter, the Company drilled 18 heavy crude oil wells and 14 high-pressure cyclic steam thermal crude oil wells at Primrose.

As part of this development plan, the Company is continuing with its Primrose thermal project which includes the Primrose North expansion as well as drilling of additional wells in Primrose South project which augments existing production. At Primrose South, production commenced from two new phases that were drilled in 2003. Average in-situ production increased to 51 mbbl/d, up 43% and 41% from Q2/2004 and Q3/2003 respectively. The Primrose North expansion continues to be on track and on budget with total capital expenditures of approximately $300 million expected to be incurred leading to first oil of 30 mbbl/d in 2006.

Late in the third quarter the Company filed a public disclosure document for regulatory approval of the Primrose East project. This will include a new facility located about 15 kilometres from its existing Primrose South steam plant and 25 kilometres from its Wolf Lake central processing facility. Once completed, Primrose East will be fully integrated with existing operations at Wolf Lake, Primrose South and Primrose North. The new facility is expected to help boost production at greater Primrose by an additional 30 mbbl/d of bitumen by 2009. The Company currently expects to complete its regulatory application by late 2005 with a regulatory decision expected in late 2006.

The Pelican Lake enhanced oil recovery project also continues on track, through production decline abatement associated with waterflood and through the second quarter drilling of additional producing wells. These activities reversed the trend of five consecutive quarters of production declines. This project seeks to significantly increase recovery efficiency on this vast blanket sand in North Alberta. To date the waterflood has provided initial production increases as expected and has shown positive waterflood response. As such, the Pelican Lake waterflood project will be expanded in 2005. In addition, Canadian Natural will pilot a further enhancement to this process by use of a polymer flood. This polymer flood pilot will commence during 2005 with a three injector, five producer pilot.

Horizon Oil Sands Project

Canadian Natural's Board of Directors recognizes the significance of and the opportunities associated with the Horizon Oil Sands Project. The Company's approach to date has been to obtain a higher level of project definition and detailed engineering than has been typical for predecessor projects. This, along with Canadian Natural retaining the role as managing contractor and breaking the Project into numerous manageable pieces that can be individually bid out to different engineering and construction firms, represents a significant departure from past industry norms.

During the third quarter, site preparation continued and bids were received for a significant portion of the Project. Bids for some components are still in the clarification stage and will necessitate the extension of final sanction for a period of 2 to 4 months. In the interim the Board of Directors has approved additional capital expenditures on the Project to continue the Project development strategy, which includes all actions required to maintain schedule (engineering, procurement and contract awards). This will result in the current expected phase one production date of mid 2008 not being impaired.

The results of bids received to date indicate that while a significant portion of the contracts to be awarded will be lump sum firm-price bid, overall costs are somewhat higher than originally estimated. The major reasons for these increases include:

- Significant increases in input steel prices to be used for the Project;
- Significant increases in input fuel costs to be used for the Project;
- Significant cost pressures associated with tight labour markets, reflecting heightened project activity levels in Western Canada, and in particular, Alberta; and
- Apparent risk premiums "built in" to certain lump sum bids as a result of continued volatility in the above items.

The current estimate for phase one construction costs now totals approximately $6.1 billion with a contingency estimated risked cost of $6.6 billion. The total for all three phases of the Project is now expected to cost approximately $9.7 billion with a contingency estimated risked cost of $10.5 billion. As a result of the Company's front-end engineering efforts, a higher degree of clarity and cost certainty has been achieved.

Management believes that while these costs are higher than previous estimates, current and future strip commodity prices continue to provide a project that is as robust as the original estimate would have been at lower price decks. Economically, the Project maintains an expected return on capital of 15% assuming the above capital levels with a long-term WTI price of US$28/bbl and a $0.78 Canada/US exchange rate. Furthermore, from an operational standpoint, Management believes that the appropriate strategies, plans and leadership team are in place to successfully execute the Project.

The Company currently employs 282 experienced staff and over 450 contract professionals who are working on the Project. As owner/manager, Canadian Natural will develop and execute this plan so as to strive for the delivery of the Project on budget.

North Sea

Canadian Natural set record quarterly production of 80 mboe/d as it utilizes its mature basin expertise, and will continue to target accretive acquisitions with exploitation upside potential. During the quarter, two producing wells and one injection well were drilled, including a new sub-sea well in the Lyell Field that is producing about 3 mbbl/d. In addition, the Playfair well was spudded in Q3/2004 and was recently completed with an expected sustained production rate of 4 mbbl/d and sufficient gas to fuel the Murchison Platform for several years.

Canadian Natural continued implementation of the natural gas reinjection project at the Banff Field in the Central North Sea with reinjection commencing in November 2004. This project is expected to increase overall reservoir recovery by approximately 17 mmbbl net to Canadian Natural, but will result in reductions in natural gas production volumes of approximately 30 mmcf/d. Late in the quarter one of the Kyle sub-sea wells was redirected to Banff utilising existing pipeline infrastructure resulting in a net production increase from this well of 2 mbbl/d.

Canadian Natural also completed the acquisition of approximately 16 mboe/d of light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interests of 100% in the T-Block (Tiffany, Toni and Thelma Fields) and 68.68% to 75.29% interests in the B-Block (Balmoral, Stirling and Glamis Fields), together with associated production facilities, including a fixed platform, a Floating Production Vessel (“FPV”) and adjacent exploration acreage which is anticipated to add further future development opportunities. Canadian Natural has identified 8 new drilling locations and 9 workovers as well as natural gas lift and waterflood opportunities on these properties. These opportunities coupled with platform and infrastructure maintenance opportunities will serve to increase production, lower operating costs and ultimately extend productive field life of the fields.

Offshore West Africa

The development of the Baobab Field, located offshore Côte d’Ivoire continued on time and on budget. Canadian Natural’s first deep water development includes eight production wells, three water injection wells and related subsea infrastructure tied back to a Floating Production Storage and Offtake (“FPSO”) vessel currently nearing completion in Singapore. To date, production testing on the four drilled production wells has met or exceeded expectations, with the result that Baobab is now expected to flow at approximately 24 mbbl/d net to Canadian Natural, when it comes on production in mid 2005, increasing to approximately 35 mbbl/d in late 2005.

The Acajou delineation well is expected to spud in late November with completion targeted for early 2005. If drilling results indicate a commercial reservoir, development could be accomplished via subsea tie-back to the East Espoir facilities or, if large enough, a stand alone development.

At East Espoir, based upon additional testing and an evaluation undertaken in 2004 that revealed a larger quantity of crude oil in place, an additional four wells are scheduled for drilling in 2005. These new producer wells will effectively exploit this additional potential and could add up to 25 mmbbl of recoverable resources from the field. The development of the nearby West Espoir Field is progressing on schedule and is expected to provide approximately 8 mbbl/d of crude oil and 30 mmcf/d of natural gas production net to Canadian Natural commencing spring 2006 through existing FPSO facilities.

Canadian Natural continues to show discipline in adhering to its core values. Additional review of seismic and geological data on Block 16 located offshore Angola indicate that while significant upside remains a possibility, it maintains a risk level outside the normal operating parameters of the Company. Hence, the Company is evaluating alternatives for its holdings in the Block.

FINANCIAL REVIEW

Canadian Natural is committed to maintaining its strong financial position so as to allow it to withstand volatile crude oil and natural gas commodity prices and the operational risks inherent in the crude oil and natural gas business environment. The Company continues to build the necessary financial capacity to complete the Horizon Oil Sands Project.

During the first nine months of 2004, strong operational results and product pricing enabled the Company to maintain debt levels at 32.5% of book capitalization despite significant capital expenditures and property acquisitions aggregating $3.2 billion. Corporate debt to cash flow was approximately 0.9 times, while debt to EBITDA was 0.8 times identical to those recorded at December 31, 2003.

The Company has used excess cash flows derived from higher than expected commodity prices to selectively acquire properties generating future cash flows in its core regions. These targeted acquisitions provide relatively quick repayment of initial investments and will provide additional free cash flow during the construction years of the Horizon Oil Sands Project while still achieving targeted returns. The acquisitions of Petrovera as well as other natural gas properties and the acquisition of properties in the central North Sea meet these reinvestment criteria and further enhance Canadian Natural's ability to complete the Horizon Oil Sands Project. This expansion of the conventional asset base also helps reduce the sole project risk exposure associated with this major development project.

During the first nine months of 2004, Canadian Natural also utilized its Normal Course Issuer Bid program administered through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") in order to repurchase and cancel 873,400 common shares for a total cost of C$33 million (C$38.01 per common share).

The Board of Directors declared a quarterly dividend of $0.10 per common share payable January 1, 2005 to Shareholders of record on December 17, 2004.

CORPORATE UPDATE

The Board of Directors reluctantly accepted the resignation of James T. Grenon from the Board of Directors. Mr. Grenon has been a Director of the Company since September 1988 and served on the Audit Committee and the Compensation Committee of the Board of Directors. The Company would like to thank Mr. Grenon for his years of dedicated service.

2005 BUDGET UPDATE

Management is currently in the process of finalizing Canadian Natural's 2005 Budget and will release the details of this budget on November 15, 2004.

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 and nine months ended September 30, 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.

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. Strategically, the acquisition fit with the Company's objective of dominating its core areas and related infrastructure. The Company achieved cost 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 Sep 30 2004	Jun 30 2004	Sep 30 2003[1]	Nine Months Ended Sep 30 2004	Sep 30 2003[1]
Revenue	**$ 2,075**	$ 1,865	$ 1,454	**$ 5,578**	$ 4,796
Net earnings attributable to common shareholders[2]	**$ 311**	$ 259	$ 201	**$ 828**	$ 1,153
Per common share – basic[3]	**$ 1.16**	$ 0.97	$ 0.75	**$ 3.09**	$ 4.29
– diluted[3]	**$ 1.13**	$ 0.97	$ 0.74	**$ 3.07**	$ 4.14
Cash flow from operations attributable to common shareholders[4]	**$ 1,041**	$ 930	$ 758	**$ 2,819**	$ 2,426
Per common share – basic[3]	**$ 3.88**	$ 3.47	$ 2.81	**$ 10.51**	$ 9.03
– diluted[3]	**$ 3.85**	$ 3.47	$ 2.78	**$ 10.44**	$ 8.81
Business combination	**$ -**	$ -	$ -	**$ 471**	$ -
Capital expenditures, net of dispositions	**$ 875**	$ 844	$ 621	**$ 2,741**	$ 1,844

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

(2) After dividend and revaluation of preferred securities.

(3) Restated to reflect two-for-one share split in May 2004.

(4) 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.

($ millions)	Three Months Ended Sep 30 2004	Jun 30 2004	Sep 30 2003	Nine Months Ended Sep 30 2004	Sep 30 2003
Net earnings attributable to common shareholders	***$ 311***	*$ 259*	*$ 201*	***$ 828***	*$ 1,153*
Non-cash items:					
Future tax on dividend on preferred securities	***(1)***	*(1)*	*(1)*	***(3)***	*(3)*
Revaluation of preferred securities, net of tax	***(5)***	*2*	*-*	***(2)***	*(14)*
Stock-based compensation expense	***119***	*50*	*32*	***225***	*137*
Depletion, depreciation and amortization	***453***	*426*	*387*	***1,268***	*1,118*
Accretion of asset retirement obligation	***14***	*10*	*16*	***35***	*46*
Unrealized risk management activities	***105***	*70*	*-*	***277***	*-*
Unrealized foreign exchange (gain) loss	***(94)***	*33*	*(11)*	***(15)***	*(239)*
Deferred petroleum revenue tax (recovery)	***(14)***	*(3)*	*1*	***(13)***	*8*
Future income tax expense	***153***	*84*	*133*	***219***	*220*
Cash flow from operations attributable to common shareholders	***$ 1,041***	*$ 930*	*$ 758*	***$ 2,819***	*$ 2,426*

The Company achieved record levels of production, reporting 508,157 boe/d before royalties for the nine months ended September 30, 2004 and 529,946 boe/d before royalties for the three months ended September 30, 2004. Production of crude oil and NGLs increased 15% to 278,052 bbl/d before royalties and natural gas production increased 6% to 1,381 mmcf/d before royalties for the nine months ended September 30, 2004. The Company also realized record quarterly crude oil and NGLs production, reporting 297,262 bbl/d before royalties for the three months ended September 30, 2004. The Company recorded strong levels of net earnings and record levels of cash flow for the nine and three months ended September 30, 2004 by continuing to follow its defined growth strategy to create shareholder value. Cash flow for the nine and three months ended September 30, 2004 increased 16% to $2,819 million and 37% to $1,041 million respectively from the comparable periods in 2003. The increase in cash flow was a result of increased production volumes and higher product prices for crude oil and NGLs. Net earnings decreased 28% to $828 million for the nine months ended September 30, 2004 but increased 55% to $311 million for the three months ended September 30, 2004 from the comparable periods in the prior year. The decrease in net earnings for the nine months ended September 30, 2004 was a result of the recognition in 2004 of an unrealized expense related to the mark-to-market of the Company's undesignated financial instruments, higher stock compensation expense, and the impact of Federal corporate income tax changes in 2003, partially offset by a larger impact of Alberta corporate tax rate reductions in 2004 than in 2003. Net earnings increased for the three months ended September 30, 2004 from the comparable period in 2003 due to higher production volumes and product prices.

OPERATING HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Crude oil and NGLs ($/bbl, except daily production)					
Daily production (bbl/d)	**297,262**	275,398	247,016	**278,052**	241,762
Sales price[(1)]	**$ 43.50**	$ 36.72	$ 31.45	**$ 38.37**	$ 33.75
Royalties	**3.59**	3.15	2.56	**3.23**	2.96
Production expense	**10.21**	9.92	10.14	**9.92**	10.57
Netback	**$ 29.70**	$ 23.65	$ 18.75	**$ 25.22**	$ 20.22
Natural gas ($/mcf, except daily production)					
Daily production (mmcf/d)	**1,396**	1,452	1,289	**1,381**	1,308
Sales price[(1)]	**$ 6.24**	$ 6.64	$ 5.57	**$ 6.40**	$ 6.52
Royalties	**1.39**	1.38	1.11	**1.35**	1.41
Production expense	**0.71**	0.66	0.63	**0.67**	0.60
Netback	**$ 4.14**	$ 4.60	$ 3.83	**$ 4.38**	$ 4.51
Barrels of oil equivalent ($/boe, except daily production)					
Daily production (boe/d)	**529,946**	517,343	461,882	**508,157**	459,785
Sales price[(1)]	**$ 40.92**	$ 38.20	$ 32.40	**$ 38.44**	$ 36.32
Royalties	**5.68**	5.55	4.46	**5.43**	5.57
Production expense	**7.59**	7.12	7.17	**7.26**	7.26
Netback	**$ 27.65**	$ 25.53	$ 20.77	**$ 25.75**	$ 23.49

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

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
WTI benchmark price (US$/bbl)	**$ 43.85**	$ 38.34	$ 30.20	**$ 39.13**	$ 30.96
Dated Brent benchmark price (US$/bbl)	**$ 41.58**	$ 35.42	$ 28.42	**$ 36.35**	$ 28.61
Differential to LLB blend (US$/bbl)	**$ 12.55**	$ 11.63	$ 8.72	**$ 11.37**	$ 7.93
Condensate benchmark price (US$/bbl)	**$ 42.66**	$ 39.17	$ 29.97	**$ 39.28**	$ 31.37
NYMEX benchmark price (US$/mmbtu)	**$ 5.85**	$ 5.97	$ 5.10	**$ 5.84**	$ 5.74
AECO benchmark price (C$/GJ)	**$ 6.32**	$ 6.45	$ 5.95	**$ 6.34**	$ 6.70
US / Canadian dollar average exchange rate (US$)	**$ 0.76**	$ 0.74	$ 0.72	**$ 0.75**	$ 0.70

World crude oil prices continued to remain strong in 2004 due to strong world-wide demand growth, particularly in the United States and Asia. World crude oil prices have also been impacted by geopolitical uncertainty in several areas of the world, resulting in concerns around the supply of crude oil. West Texas Intermediate ("WTI") averaged US$39.13 per bbl for the nine months ended September 30, 2004, up 26% compared to US$30.96 per bbl in the comparable period in 2003. WTI averaged US$43.85 per bbl in the third quarter of 2004, up 45% from US$30.20 per bbl in the comparable period in 2003, and up 14% from US$38.34 per bbl in the prior quarter. World crude oil prices have been further impacted by weather related issues causing production disruptions in the United States Gulf Coast. The impact of the higher WTI price was reduced as a result of wider heavy crude oil differentials, which increased 43% to US$11.37 per bbl and 44% to US$12.55 per bbl for the nine months and three months ended September 30, 2004 from the comparable periods in 2003. The heavy crude oil differentials increased 8% from US$11.63 per bbl in the prior quarter of 2004. Realized crude oil prices were also impacted by the strengthening Canadian dollar.

North American natural gas prices remained strong due to concerns around supply and the impact of higher crude oil prices. AECO natural gas prices decreased 5% to average $6.34 per GJ for the nine months ended September 30, 2004 from $6.70 per GJ in the comparable period in 2003. NYMEX natural gas prices increased 2% to average US$5.84 per mmbtu for the nine months ended September 30, 2004 from US$5.74 per mmbtu in the comparable period in 2003. AECO natural gas prices increased 6% to average $6.32 per GJ in the third quarter of 2004 from $5.95 per GJ in the comparable period in 2003, and decreased 2% compared to $6.45 per GJ in the prior quarter. NYMEX natural gas prices increased 15% to average US$5.85 per mmbtu in the third quarter of 2004 from US$5.10 per mmbtu in the comparable period in 2003, but decreased 2% from US$5.97 per mmbtu in the prior quarter. The decrease in North American natural gas prices from the second quarter is due to mild weather across much of North America and strong storage levels.

PRODUCT PRICES

	Three Months Ended						Nine Months Ended			
		Sep 30 2004		Jun 30 2004		Sep 30 2003		**Sep 30 2004**		Sep 30 2003
Crude oil and NGLs ($/bbl)[1]										
North America	**$**	**38.31**	$	32.31	$	28.22	**$**	**33.93**	$	30.83
North Sea	**$**	**57.39**	$	49.22	$	39.63	**$**	**50.85**	$	42.10
Offshore West Africa	**$**	**53.86**	$	49.34	$	37.37	**$**	**48.33**	$	36.50
Company average	**$**	**43.50**	$	36.72	$	31.45	**$**	**38.37**	$	33.75
Natural gas ($/mcf)[1]										
North America	**$**	**6.36**	$	6.78	$	5.70	**$**	**6.51**	$	6.66
North Sea	**$**	**3.17**	$	3.28	$	2.57	**$**	**3.84**	$	2.91
Offshore West Africa	**$**	**6.31**	$	5.18	$	4.58	**$**	**5.36**	$	4.60
Company average	**$**	**6.24**	$	6.64	$	5.57	**$**	**6.40**	$	6.52
Percentage of revenue (excluding midstream revenue)										
Crude oil and NGLs		**60%**		51%		52%		**55%**		49%
Natural gas		**40%**		49%		48%		**45%**		51%

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

Realized crude oil prices increased 14% to average $38.37 per bbl for the nine months ended September 30, 2004, up from $33.75 per bbl in the comparable period in 2003. The realized crude oil price increased 38% to average $43.50 per bbl in the third quarter of 2004, up from $31.45 per bbl in the comparable period in 2003 and up 18% from the previous quarter price of $36.72 per bbl. The increase in the realized crude oil prices is due mainly to higher world crude oil prices.

The Company's realized natural gas price decreased 2% to average $6.40 per mcf for the nine months ended September 30, 2004, down from $6.52 per mcf in the comparable period in 2003. The realized natural gas price increased 12% to $6.24 per mcf in the third quarter of 2004, up from $5.57 per mcf in the comparable period in 2003, but decreased 6% from $6.64 per mcf in the prior quarter due to changes in supply and demand fundamentals.

North America

North American realized crude oil prices increased 10% to average $33.93 per bbl for the nine months ended September 30, 2004, up from $30.83 per bbl in the comparable period in 2003. The realized crude oil price increased 36% to average $38.31 per bbl in the third quarter of 2004, up from $28.22 per bbl in the comparable period in 2003 and up 19% from the previous quarter price of $32.31 per bbl. The increase in the realized crude oil price is due mainly to higher world crude oil prices, partially offset by wider heavy crude oil differentials and the stronger Canadian dollar.

The Company continues to focus on its crude oil marketing strategy, which includes supporting pipeline projects that will provide capacity to transport crude oil to new markets, working with PADD II refiners to add incremental heavy crude oil conversion capacity, and blending strategy. The blending strategy, or Synbit strategy, entails blending synthetic crude oil with heavy crude oil to produce a product very similar to medium sour crude. The Company is currently selling 55,000 bbl/d and anticipates having the capacity to blend 144,000 bbl/d later this year.

North American realized natural gas price decreased 2% to average $6.51 per mcf for the nine months ended September 30, 2004, down from $6.66 per mcf in the comparable period in 2003. The realized natural gas price increased 12% to $6.36 per mcf in the third quarter of 2004, up from $5.70 per mcf in the comparable period in 2003, but decreased 6% from $6.78 per mcf in the prior quarter due to fluctuations in the North American benchmark natural gas price.

North Sea

North Sea realized crude oil prices increased 21% to average $50.85 per bbl for the nine months ended September 30, 2004, up from $42.10 per bbl in the comparable period in 2003. The realized crude oil price increased 45% to average $57.39 per bbl in the third quarter of 2004, up from $39.63 per bbl in the comparable period in 2003 and up 17% from the previous quarter price of $49.22 per bbl. The increase in the realized crude oil price is due mainly to higher world crude oil prices and fluctuations in the Brent differential.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 32% to average $48.33 per bbl for the nine months ended September 30, 2004, up from $36.50 per bbl in the comparable period in 2003. The realized crude oil price increased 44% to average $53.86 per bbl in the third quarter of 2004, up from $37.37 per bbl in the comparable period in 2003 and up 9% from the previous quarter price of $49.34 per bbl. The increase in the realized crude oil price is due mainly to higher world crude oil prices.

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

	Q3 2004	Q2 2004	Q3 2003
Canadian Natural's Wellhead Price[1]			
Light crude oil and NGLs (C$/bbl)	**$ 48.77**	$ 44.83	$ 35.23
Pelican Lake crude oil (C$/bbl)	**$ 36.39**	$ 31.90	$ 27.89
Primary heavy crude oil (C$/bbl)	**$ 35.40**	$ 28.22	$ 25.58
Thermal heavy crude oil (C$/bbl)	**$ 35.19**	$ 27.67	$ 24.39
Natural gas (C$/mcf)	**$ 6.36**	$ 6.78	$ 5.70

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

DAILY PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Crude oil and NGLs (bbl/d)					
North America	**214,336**	203,741	174,838	**203,449**	174,378
North Sea	**71,517**	60,105	60,193	**62,938**	57,658
Offshore West Africa	**11,409**	11,552	11,985	**11,665**	9,726
Total	**297,262**	275,398	247,016	**278,052**	241,762
Natural gas (mmcf/d)					
North America	**1,336**	1,389	1,229	**1,319**	1,258
North Sea	**53**	55	49	**54**	43
Offshore West Africa	**7**	8	11	**8**	7
Total	**1,396**	1,452	1,289	**1,381**	1,308
Total barrel of oil equivalent (boe/d)	**529,946**	517,343	461,882	**508,157**	459,785
Product mix					
Light crude oil and NGLs	**24%**	23%	26%	**24%**	25%
Pelican Lake crude oil	**4%**	4%	5%	**4%**	6%
Primary heavy crude oil	**18%**	19%	15%	**19%**	14%
Thermal heavy crude oil	**10%**	7%	8%	**8%**	8%
Natural gas	**44%**	47%	46%	**45%**	47%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Crude oil and NGLs (bbl/d)					
North America	**187,098**	177,643	153,043	**177,625**	151,525
North Sea	**71,396**	59,983	60,057	**62,831**	57,654
Offshore West Africa	**11,108**	11,197	11,624	**11,326**	9,433
Total	**269,602**	248,823	224,724	**251,782**	218,612
Natural gas (mmcf/d)					
North America	**1,031**	1,094	980	**1,033**	981
North Sea	**53**	54	49	**54**	43
Offshore West Africa	**7**	8	10	**8**	7
Total	**1,091**	1,156	1,039	**1,095**	1,031
Total barrel of oil equivalent (boe/d)	**451,462**	441,525	397,901	**434,239**	390,478

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.

The Company achieved record levels of production on a barrel of oil equivalent basis for the nine months ended September 30, 2004. Production before royalties on a barrel of crude oil equivalent was 508,157 bbl/d for the nine months ended September 30, 2004. The increase in production was due to the Company's extensive capital expenditure program and recent acquisitions.

Total crude oil and NGLs production before royalties for the nine and three months ended September 30, 2004 increased 15% or 36,290 bbl/d and 20% or 50,246 bbl/d respectively from the comparable periods in 2003. Crude oil and NGLs production before royalties for the third quarter increased 8% or 21,864 bbl/d from the prior quarter and was in line with the Company's guidance of 284,000 to 307,000 bbl/d previously provided.

Natural gas production before royalties continues to represent the Company's largest product offering. Natural gas production before royalties for the nine and three months ended September 30, 2004 increased 6% or 73 mmcf/d and 8% or 107 mmcf/d respectively from the comparable periods in 2003. The increase was a result of a successful natural gas drilling program and the acquisition of certain resource properties in the Company's North American segment. Natural gas production before royalties in the third quarter of 2004 decreased 4% or 56 mmcf/d from the prior quarter due to normal production declines but was in line with the Company's guidance of 1,375 to 1,413 mmcf/d.

The Company expects annual production levels before royalties to average 1,371 to 1,383 mmcf/d of natural gas and 279 to 288 mbbl/d of crude oil and NGLs in 2004. Fourth quarter 2004 production guidance before royalties is 1,350 to 1,385 mmcf/d of natural gas and 291 to 311 mbbl/d of crude oil and NGLs.

North America

Crude oil and NGLs production before royalties in North America for the nine and three months ended September 30, 2004 increased 17% or 29,071 bbl/d and 23% or 39,498 bbl/d respectively from the comparable periods in 2003 due to the development of the Primrose thermal crude oil project and the acquisition of Petrovera. Crude oil and NGLs production before royalties in the third quarter of 2004 increased 5% or 10,595 bbl/d from the prior quarter due to the commencement of production from wells drilled as part of the Primrose thermal project.

North America natural gas production before royalties for the nine and three months ended September 30, 2004 increased 5% or 61 mmcf/d and 9% or 107 mmcf/d respectively from the comparable periods in 2003. North American production of natural gas increased as a result of the Petrovera acquisition, the acquisition of additional properties located in Northeast British Columbia and Northwest Alberta, and the focus on natural gas drilling. North American natural gas production before royalties decreased 4% or 53 mmcf/d from the prior quarter. The decline in production is mainly due to the fact that the majority of the Company's natural gas drilling is concentrated in the winter months. As a result, the third quarter is typified by declines in natural gas production and a reduction in drilling activity. In addition, production of natural gas was impacted by the shut-in of 13 mmcf/d of natural gas in the Athabasca Wabiskaw-McMurray oilsands area effective July 1, 2004.

North Sea

Crude oil production before royalties from the North Sea for the nine and three months ended September 30, 2004 increased 9% or 5,280 bbl/d and 19% or 11,324 bbl/d respectively from the comparable periods in 2003. Crude oil production before royalties in the third quarter increased 19% or 11,412 bbl/d from the previous quarter. The increase in production was due to the ongoing drilling, recompletion and waterflood optimization program at the Ninian and Murchison Fields and the acquisition of light crude oil producing properties in the Central North Sea in the third quarter of 2004.

Natural gas production before royalties in the North Sea for the nine and three months ended September 30, 2004 increased 26% or 11 mmcf/d and 8% or 4 mmcf/d respectively from the comparable periods in 2003 due to the acquisition in the Central North Sea in the third quarter of 2004 and the increased working interests acquired in the Banff Field during 2003. Production of natural gas in the Banff Field is expected to decline due to the commencement of the natural gas reinjection program in the fourth quarter of 2004.

Offshore West Africa

Offshore West Africa crude oil production before royalties for the nine months ended September 30, 2004 increased 20% or 1,939 bbl/d due to the perforation of the upper zone of the East Espoir Field in the third quarter of 2003 and the completion of the fourth water injection well and two additional producing wells in 2003. Crude oil production before royalties for the three months ended September 30, 2004 decreased 5% or 576 bbl/d from the comparable period in 2003 and 1% or 143 bbl/d from the prior quarter.

Natural gas production before royalties in Offshore West Africa increased 14% or 1 mmcf/d for the nine months ended September 30, 2004 but decreased 36% or 4 mmcf/d for the three months ended September 30, 2004 from the comparable periods in the prior year.

ROYALTIES

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Crude oil and NGLs ($/bbl)					
North America	**$ 4.87**	$ 4.14	$ 3.52	**$ 4.31**	$ 4.04
North Sea	**$ 0.09**	$ 0.10	$ 0.09	**$ 0.09**	$ -
Offshore West Africa	**$ 1.42**	$ 1.52	$ 1.13	**$ 1.40**	$ 1.10
Company average	**$ 3.59**	$ 3.15	$ 2.56	**$ 3.23**	$ 2.96
Natural gas ($/mcf)					
North America	**$ 1.45**	$ 1.44	$ 1.16	**$ 1.41**	$ 1.46
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.17**	$ 0.16	$ 0.14	**$ 0.16**	$ 0.14
Company average	**$ 1.39**	$ 1.38	$ 1.11	**$ 1.35**	$ 1.41
Company average ($/boe)	**$ 5.68**	$ 5.55	$ 4.46	**$ 5.43**	$ 5.57
Percentage of revenue[(1)]					
Crude oil and NGLs	**8%**	9%	8%	**8%**	9%
Natural gas	**22%**	21%	20%	**21%**	22%
Boe	**14%**	15%	14%	**14%**	15%

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

North America

North American crude oil and NGLs royalties increased from both the comparable periods in 2003 and the prior quarter due to higher benchmark crude oil prices.

Natural gas royalties as a percentage of revenue fluctuated from both the comparable periods in 2003 and the prior quarter as a result of fluctuations in natural gas prices and the strong correlation of royalties to natural gas prices.

North Sea

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

Offshore West Africa

Offshore West Africa production is governed by the terms of the Production Sharing Contract ("PSC"). Under the PSC, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover the capital and operating costs carried by the Company on behalf of the Government State Oil Company. These revenues are reported as sales revenue. Profit revenue is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of revenue attributable to the Company's equity interest is reported as either royalty expense or current tax expense in accordance with the PSC.

PRODUCTION EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Crude oil and NGLs ($/bbl)					
North America	**$ 9.10**	$ 8.91	$ 9.27	**$ 8.89**	$ 9.39
North Sea	**$ 13.88**	$ 13.84	$ 13.25	**$ 13.68**	$ 14.29
Offshore West Africa	**$ 8.05**	$ 7.43	$ 7.11	**$ 7.52**	$ 9.61
Company average	**$ 10.21**	$ 9.92	$ 10.14	**$ 9.92**	$ 10.57
Natural gas ($/mcf)					
North America	**$ 0.63**	$ 0.60	$ 0.58	**$ 0.61**	$ 0.57
North Sea	**$ 2.48**	$ 1.92	$ 1.60	**$ 2.01**	$ 1.39
Offshore West Africa	**$ 1.39**	$ 1.38	$ 1.24	**$ 1.33**	$ 1.51
Company average	**$ 0.71**	$ 0.66	$ 0.63	**$ 0.67**	$ 0.60
Company average ($/boe)	**$ 7.59**	$ 7.12	$ 7.17	**$ 7.26**	$ 7.26

North America

North American crude oil and NGLs production expense for the nine and three months ended September 30, 2004 decreased from the comparable periods in 2003. The decrease was due to the impact of a lower steam oil ratio for the Company's thermal heavy crude oil operations, resulting in a lower cost per barrel for fuel used in the generation of steam. North American natural gas production expense per mcf for the nine and three months ended September 30, 2004 increased from the comparable periods in 2003 primarily due to a general increase in service costs associated with increased industry activity and higher costs associated with colder weather experienced early in 2004.

North Sea

North Sea crude oil production expense varies on a per barrel basis from both the comparable periods 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.

Offshore West Africa

Offshore West Africa crude oil production expenses 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.

MIDSTREAM

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2004**	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Revenue	**$ 17**	$ 17	$ 13	**$ 50**	$ 45
Production expense	**6**	5	3	**15**	11
Midstream cash flow	**11**	12	10	**35**	34
Depreciation	**2**	1	2	**5**	6
Segment earnings before taxes	**$ 9**	$ 11	$ 8	**$ 30**	$ 28

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 80% 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 nine and three months ended September 30, 2004 increased from the comparable periods in 2003 due to the expansion of the ECHO Pipeline.

DEPLETION, DEPRECIATION AND AMORTIZATION[2]

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003[1]	**Sep 30 2004**	Sep 30 2003[1]
Expense ($ millions)	**$ 451**	$ 425	$ 385	**$ 1,263**	$ 1,112
$/boe	**$ 9.27**	$ 9.01	$ 9.06	**$ 9.07**	$ 8.86

(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") for the nine and three months ended September 30, 2004 increased in total and per boe from the comparable periods in the prior year. The increase in total DD&A was due to higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with recent acquisitions, and future abandonment costs associated with the acquisition of additional properties in the North Sea.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003[1]	**Sep 30 2004**	Sep 30 2003[1]
Expense ($ millions)	**$ 14**	$ 10	$ 16	**$ 35**	$ 46
$/boe	**$ 0.29**	$ 0.22	$ 0.38	**$ 0.25**	$ 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			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Net expense ($ millions)	**$ 31**	$ 27	$ 22	**$ 81**	$ 63
$/boe	**$ 0.62**	$ 0.58	$ 0.51	**$ 0.58**	$ 0.50

Administration expense for the nine and three months ended September 30, 2004 increased in total and on a per boe basis from the comparable periods in 2003 due to higher staffing levels associated with the Company's expanding asset base.

STOCK-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Stock option plan ($ millions)	**$ 119**	$ 50	$ 32	**$ 225**	$ 137
Share bonus plan ($ millions)	**1**	2	-	**8**	-
Total ($ millions)	**$ 120**	$ 52	$ 32	**$ 233**	$ 137
$/boe	**$ 2.45**	$ 1.11	$ 0.77	**$ 1.67**	$ 1.10

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 Company has recorded a liability at September 30, 2004 of $315 million (June 30, 2004 - $211 million; September 30, 2003 - $124 million) for expected cash settlements of stock options 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). 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 stock-based compensation expense relating to the Company's Option Plan for the nine months ended September 30, 2004 is $225 million ($151 million after tax).

For the nine months ended September 30, 2004, the Company paid $66 million for stock options surrendered for cash settlement (six months ended June 30, 2004 - $45 million; nine months ended September 30, 2003 - $10 million).

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 may be awarded based on the Company's and the employee's performance and subsequently 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 nine months ended September 30, 2004, the Company has recognized $8 million ($5 million after tax) of compensation expense under the Share Bonus Plan.

INTEREST EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2004	Jun 30 2004	Sep 30 2003(1)	**Sep 30 2004**	Sep 30 2003(1)
Interest expense, net ($ millions)	**$ 45**	$ 46	$ 44	**$ 134**	$ 151
$/boe	**$ 0.94**	$ 0.98	$ 1.04	**$ 0.97**	$ 1.20
Average effective interest rate	**5.1%**	4.9%	5.7%	**5.2%**	5.9%

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

Interest expense for the nine and three months ended September 30, 2004 was impacted by the Company prospectively adopting CICA Accounting Guideline 13, "Hedging Relationships" and EIC 128. As a result of the adoption of this accounting guideline, $25 million of realized gains on certain of its fixed to floating interest rate swaps are included in risk management activities. Interest expense decreased on a total and boe basis for the nine months ended September 30, 2004 from the comparable period in 2003 mainly due to the lower borrowing rates. Interest expense increased slightly on a total basis for the three months ended September 30, 2004 from the comparable period in 2003 due to the higher debt levels outstanding, partially offset by lower borrowing rates.

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 activities.

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 losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on interest rate contracts not designated as hedges are included in risk management activities.

The Company enters into cross currency swap agreements to manage its currency exposure on long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

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 into 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 nine and three months ended September 30, 2004:

RISK MANAGEMENT

($ millions)	Three Months Ended Sep 30 2004	Jun 30 2004	Sep 30 2003	Nine Months Ended Sep 30 2004	Sep 30 2003
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 176**	$ 108	$ 11	**$ 321**	$ 107
Natural gas financial instruments	**1**	2	9	**3**	85
Interest rate swaps	**(6)**	(10)	(9)	**(25)**	(27)
Total	**$ 171**	$ 100	$ 11	**$ 299**	$ 165
Unrealized loss (gain)					
Crude oil and NGLs financial instruments	**$ 107**	$ 61	$ -	**$ 274**	$ -
Natural gas financial instruments	**-**	(3)	-	**-**	-
Interest rate swaps	**(2)**	12	-	**3**	-
Total	**$ 105**	$ 70	$ -	**$ 277**	$ -
Total	**$ 276**	$ 170	$ 11	**$ 576**	$ 165

The effect of the realized loss from crude oil and NGLs and natural gas financial instruments was to reduce the Company's average realized prices as follows:

	Three Months Ended Sep 30 2004	Jun 30 2004	Sep 30 2003	Nine Months Ended Sep 30 2004	Sep 30 2003
Crude oil and NGLs ($/bbl)	**$ 6.45**	$ 4.31	$ 0.48	**$ 4.22**	$ 1.62
Natural gas ($/mcf)	**$ 0.01**	$ 0.01	$ 0.07	**$ 0.01**	$ 0.23

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

	Three Months Ended			Nine Months Ended	
($ millions, except interest rates)	**Sep 30 2004**	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Interest expense as per the financial statements	**$ 45**	$ 46	$ 44	**$ 134**	$ 151
Less: realized risk management gain	**(6)**	(10)	(9)	**(25)**	(27)
	$ 39	$ 36	$ 35	**$ 109**	$ 124
Average effective interest rate	**4.4%**	3.9%	4.5%	**4.2%**	4.8%

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2004**	Jun 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Realized foreign exchange loss (gain)	**$ 1**	$ (10)	$ 3	**$ (13)**	$ 14
Unrealized foreign exchange (gain) loss	**(94)**	33	(11)	**(15)**	(239)
	$ (93)	$ 23	$ (8)	**$ (28)**	$ (225)

The majority of the unrealized foreign exchange (gain) loss is related to the fluctuation in the Canadian dollar in relation to the US dollar. The Canadian dollar ended the third quarter of 2004 at US$0.79 compared to US$0.77 at December 31, 2003 (June 30, 2004 – US$0.75; September 30, 2003 – US$0.74).

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 **Sep 30 2004**	Jun 30 2004	Sep 30 2003	Nine Months Ended **Sep 30 2004**	Sep 30 2003
Taxes other than income tax					
Current	**$ 75**	$ 52	$ 28	**$ 162**	$ 73
Deferred	**(13)**	(3)	1	**(12)**	8
Total	**$ 62**	$ 49	$ 29	**$ 150**	$ 81
Current income tax					
North America – Current income tax	**$ 6**	$ 45	$ 12	**$ 88**	$ 40
North America – Large corporations tax	**2**	1	5	**6**	15
North Sea	**(19)**	14	5	**18**	21
Offshore West Africa	**3**	4	3	**10**	7
Total	**$ (8)**	$ 64	$ 25	**$ 122**	$ 83
Future income tax expense	**$ 153**	$ 84	$ 133	**$ 219**	$ 220
Effective income tax rate	**32.0%**	36.0%	43.9%	**29.1%**	21.0%

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 crude oil prices and increased production levels.

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships and the related income taxes will be payable in the following year. Current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending 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 for the nine months ended September 30, 2004 decreased to $6 million from $15 million 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. The decrease in North American current income tax expense is due to increased capital spending and payments made in relation to stock compensation expense resulting in lower taxable income.

The North Sea recorded a recovery of current income tax expense in the third quarter of 2004 due to the tax pools acquired in a recent acquisition being immediately deductible.

For the nine months ended September 30, 2004, the North American 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 the Federal and Provincial tax rate reductions, the future income tax liability in North America was decreased by $247 million in 2003.

The following table shows the effect of non-recurring benefits on income taxes:

($ millions, except income tax rates)	Three Months Ended **Sep 30 2004**	Three Months Ended Jun 30 2004	Three Months Ended Sep 30 2003	Nine Months Ended **Sep 30 2004**	Nine Months Ended Sep 30 2003
Income tax as reported					
Current income tax (recovery)	**$ (8)**	$ 64	$ 25	**$ 122**	$ 83
Future income tax expense	**153**	84	133	**219**	220
	145	148	158	**341**	303
Alberta corporate tax rate reduction	**-**	-	-	**66**	31
Federal corporate tax rate reduction	**-**	-	-	**-**	216
Total	**$ 145**	$ 148	$ 158	**$ 407**	$ 550
Expected effective income tax rate	**32.0%**	36.0%	43.9%	**34.7%**	38.0%

CAPITAL EXPENDITURES

($ millions)	Three Months Ended Sep 30 2004	Jun 30 2004	Sep 30 2003	Nine Months Ended Sep 30 2004	Sep 30 2003
Business combination	**$ -**	$ -	$ -	**$ 471**	$ -
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 290**	$ 277	$ 106	**$ 603**	$ 307
Land acquisition and retention	**37**	39	53	**107**	110
Seismic evaluations	**25**	11	12	**68**	52
Well drilling, completion and equipping	**221**	231	256	**1,035**	842
Pipeline and production facilities	**190**	166	133	**636**	389
Total net reserve replacement expenditures	**763**	724	560	**2,449**	1,700
Horizon Oil Sands Project	**84**	103	32	**233**	100
Midstream	**2**	3	5	**5**	9
Abandonments	**14**	6	14	**27**	20
Head office	**12**	8	10	**27**	15
Total net capital expenditures	**$ 875**	$ 844	$ 621	**$ 2,741**	$ 1,844
By segment					
North America	**$ 339**	$ 578	$ 407	**$ 1,743**	$ 1,338
North Sea	**370**	75	99	**521**	232
Offshore West Africa	**54**	71	54	**185**	130
Horizon Oil Sands Project	**84**	103	32	**233**	100
Midstream	**2**	3	5	**5**	9
Abandonments	**14**	6	14	**27**	20
Head office	**12**	8	10	**27**	15
Total	**$ 875**	$ 844	$ 621	**$ 2,741**	$ 1,844

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 nine months ended September 30, 2004, capital expenditures were $2,741 million, excluding the acquisition of Petrovera, compared to $1,844 million in the comparable period in 2003. The increase in capital expenditures was a result of property acquisitions made in the North America and North Sea segments. The Company continues to make significant progress on its larger, future-growth projects while maintaining its focus on existing assets. The Company drilled a total of 1,116 net wells consisting of 537 natural gas wells, 221 crude oil wells, 276 stratigraphic test and service wells, and 82 wells that were dry and abandoned compared to 1,358 net wells in the first nine months of 2003. The Company achieved an overall success rate of 90%, 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 its asset base.

Capital expenditures in the third quarter of 2004 were $875 million compared to $621 million in the comparable period in 2003. In the third quarter the Company drilled 145 net wells, including 6 stratigraphic test and service wells.

North America

North America accounted for over 70% of the total capital expenditures in the first nine months of 2004 compared to over 78% in the comparable period in the prior year.

During the third quarter, the Company drilled 99 net wells targeting natural gas, including 26 wells in North Alberta and 19 wells in Northwest Alberta. In addition, a total of 43 shallow gas wells were drilled in South Alberta compared to 196 wells in 2003. The shallow gas program was impacted by wetter than normal weather conditions and an intentional reduction as part of capital reallocations made as a result of acquisitions completed during the year. The Company also drilled 36 net wells targeting crude oil during the third quarter 2004. These wells were concentrated in the Company's crude oil region of North Alberta where 22 primary heavy crude oil wells were drilled. Also included in this figure were 14 high-pressure horizontal thermal crude oil wells that were drilled and completed at Primrose as part of the 2004 development strategy of the area.

As part of the development of the Company's heavy crude oil resources, the Company is continuing with its Primrose thermal project, which includes the Primrose North expansion project and drilling additional wells in the Primrose South project augmenting existing production. At Primrose South, production was commissioned from the two new phases that commenced construction in 2003. The Primrose North expansion continues to be on track and on budget with total capital expenditures of approximately $300 million expected to be incurred, leading to first oil of 30 mbbl/d in 2006.

Late in the third quarter, the Company filed a public disclosure document for regulatory approval of its Primrose East project, a new facility located about 15 kilometres from its existing Primrose South steam plant and 25 kilometres from its Wolf Lake central processing facility. Once completed, Primrose East will be fully integrated with existing operations at Wolf Lake, Primrose South and Primrose North. The Company currently expects to complete its regulatory application by late 2005 with a regulatory decision expected in late 2006.

The Pelican Lake enhanced crude oil recovery project also continues on track. To date, the waterflood has provided initial production increases as expected and has shown positive waterflood response. The waterflood project will be expanded in 2005 and the Company plans to enhance the process by use of a polymer flood.

In the Horizon Oil Sands Project ("Horizon Project"), work on the third phase of front-end engineering, Engineering Design Specification ("EDS"), was completed. The EDS provides 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. During the third quarter, site preparation continued and bids were received for a significant portion of the Horizon Project. Bids for some components are still in the clarification stage and will necessitate the extension of final sanction for a period of 2 to 4 months. In the interim the Board of Directors has approved additional capital expenditures on the Horizon Project to continue the Project development strategy, which includes all actions required to maintain schedule (engineering, procurement and contract awards). This will result in the current expected phase one production date of mid 2008 not being impaired. The current estimate for phase one construction costs now totals approximately $6.1 billion with a contingency estimated risked cost of $6.6 billion. The total for all three phases of the Horizon Project is now expected to cost approximately $9.7 billion with a contingency estimated risked cost of $10.5 billion.

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. The new facilities are expected to be operational in the fourth quarter of 2004.

North Sea

In the third quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter two producing wells and one injection well were drilled, including a new sub-sea well in the Lyell Field.

During the third quarter of 2004, the Company acquired certain light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma Fields) and B-Block (Balmoral, Stirling and Glamis Fields), together with associated production facilities, including a fixed platform Floating Production Vessel ("FPV") and adjacent exploration acreage. The Company equity interests in the producing fields acquired are:

T-Block	Tiffany, Toni and Thelma	100.00%
B-Block	Balmoral	70.20%
	Glamis	75.29%
	Stirling	68.68%

In addition, the Company continued with the implementation of the natural gas reinjection project at the Banff Field in the Central North Sea with reinjection expected to commence in November 2004.

Offshore West Africa

Offshore West Africa capital expenditures include the ongoing development of the Baobab Field where development drilling is ongoing. To date, production testing on four producing wells has met or exceeded expectations. In addition, the Floating Production, Storage and Offtake Vessel ("FPSO") is nearing completion and sub-sea equipment is being manufactured.

The Acajou delineation well is expected to spud in late November with completion targeted for early 2005. If drilling results indicate a commercial reservoir, development could be accomplished via subsea tie-back to the East Espoir facilities or, if large enough, a stand alone development.

At East Espoir, an additional four wells are scheduled for drilling in early 2005 as a result of additional testing and evaluation that revealed a larger quantity of crude oil in place, based upon reservoir studies and production history to date. These new producer wells will effectively exploit this additional potential and could increase the recoverable resources from the field.

The planned development of the nearby West Espoir Field was sanctioned by Partners during the third quarter with various components out for bid. The development is progressing on schedule and is expected to commence production in the spring of 2006 through existing FPSO facilities.

Finally, additional review of seismic and geological data on Block 16 located offshore Angola indicates that while significant upside remains a possibility, its risk level is outside the normal operating parameters of the Company. As a result, the Company is evaluating alternatives for its holdings in the Block.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2004**	Jun 30 2004	Dec 31 2003[(1)]	Sep 30 2003[(1)]
Working capital deficit[(2)]	**$ 633**	$ 444	$ 505	$ 527
Long-term debt	**$ 3,314**	$ 3,609	$ 2,645	$ 2,766
Shareholders' equity				
Preferred securities	**$ 101**	$ 107	$ 103	$ 108
Share capital	**2,400**	2,393	2,353	2,348
Retained earnings	**4,372**	4,090	3,650	3,435
Foreign currency translation adjustment	**1**	-	3	9
Total	**$ 6,874**	$ 6,590	$ 6,109	$ 5,900
Debt to cash flow[(2)(3)]	**0.9x**	1.1x	0.9x	0.9x
Debt to EBITDA[(2)(3)]	**0.8x**	1.0x	0.8x	0.8x
Debt to book capitalization[(2)]	**32.5%**	35.4%	31.6%	33.4%
Debt to market capitalization[(2)]	**19.6%**	25.0%	24.2%	28.1%
After tax return on average common shareholders' equity[(3)]	**17.2%**	16.0%	25.6%	26.3%
After tax return on average capital employed[(2)(3)]	**12.3%**	11.5%	16.6%	16.4%

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

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

(3) Based on trailing 12-month activity.

At September 30, 2004, the working capital deficit amounted to $633 million and includes the current portion of other long-term liabilities of $534 million, consisting of stock based compensation of $243 million and the mark to market valuation of certain Risk Management financial derivative instruments of $291 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 September 30, 2004. At September 30, 2004, the Company had no current portion of long-term debt and undrawn bank lines of credit of $921 million.

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

Shareholders of the Company approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2004. As at September 30, 2004, there were 268,024,000 common shares outstanding. As at October 28, 2004, there were 268,028,000 common shares outstanding.

In January 2004, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 13,380,770 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 September 30, 2004, the Company had purchased 873,400 common shares for a total cost $33 million at an average purchase price of $38.01 per common share.

In February 2004, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share in 2004, up from the previous level of $0.30 per common share. The 33% increase recognized the stability of the Company's increased cash flow and provided 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.

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 $277 million ($185 million, net of tax) for the nine months ended September 30, 2004 relating to its financial instruments. The unrealized loss assumes that all unsettled derivative financial instruments were settled on September 30, 2004 and were valued based on market conditions existing at that 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.

SENSITIVITY ANALYSIS[1]

The following table is indicative of the annualized sensitivities of cash flow and net earnings from changes in certain key variables. The analysis is based on business conditions and production volumes during the third quarter of 2004. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant.

	Cash flow from operations[2] ($ millions)	Cash flow from operations[2] (per common share, basic)	Net earnings[2] ($ millions)	Net earnings[2] (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl[3]				
Excluding financial derivatives	$ 98	$ 0.37	$ 69	$ 0.26
Including financial derivatives	$ 78	$ 0.29	$ 56	$ 0.21
Natural gas – AECO C$0.10/mcf[3]				
Excluding financial derivatives	$ 36	$ 0.13	$ 23	$ 0.08
Including financial derivatives	$ 36	$ 0.13	$ 22	$ 0.08
Volume changes				
Crude oil – 10,000 bbl/d	$ 91	$ 0.34	$ 49	$ 0.18
Natural gas – 10 mmcf/d	$ 16	$ 0.06	$ 6	$ 0.02
Foreign currency rate change				
$0.01 change in C$ in relation to US$[3]				
Excluding financial derivatives	$ 61	$ 0.24	$ 25	$ 0.09
Including financial derivatives	$ 61 - 64	$ 0.23 – 0.24	$ 23 – 25	$ 0.07 – 0.09
Interest rate change - 1%	$ 13	$ 0.05	$ 13	$ 0.05

(1) The sensitivities are calculated based on 2004 third 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

($/boe, except daily production)	Three Months Ended Sep 30 2004	Three Months Ended Jun 30 2004	Three Months Ended Sep 30 2003	Nine Months Ended Sep 30 2004	Nine Months Ended Sep 30 2003
Daily production (boe/d)	**529,946**	517,343	461,882	**508,157**	459,785
Sales price[1]	**$ 40.92**	$ 38.20	$ 32.40	**$ 38.44**	$ 36.32
Royalties	**5.68**	5.55	4.46	**5.43**	5.57
Production expense[2]	**7.59**	7.12	7.17	**7.26**	7.26
Netback	**27.65**	25.53	20.77	**25.75**	23.49
Midstream contribution[2]	**(0.25)**	(0.24)	(0.24)	**(0.25)**	(0.27)
Administration	**0.62**	0.58	0.51	**0.58**	0.50
Share bonus plan	**0.03**	0.05	-	**0.06**	-
Interest	**0.94**	0.98	1.04	**0.97**	1.20
Risk management activities loss – realized	**3.51**	2.12	0.25	**2.15**	1.32
Foreign exchange loss (gain) – realized	**0.01**	(0.22)	0.11	**(0.09)**	0.12
Taxes other than income tax (current)	**1.55**	1.08	0.64	**1.17**	0.58
Current income tax (North America)	**0.12**	0.95	0.28	**0.63**	0.32
Current income tax (Large corporations tax)	**0.06**	-	0.12	**0.04**	0.12
Current income tax (North Sea)	**(0.42)**	0.32	0.10	**0.12**	0.17
Current income tax (Offshore West Africa)	**0.07**	0.08	0.07	**0.07**	0.05
Cash flow	**$ 21.41**	$ 19.83	$ 17.89	**$ 20.30**	$ 19.38

(1) Including transportation costs.

(2) Excluding intersegment eliminations.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	Sep 30 2004	Dec 31 2003(1)
ASSETS		
Current assets		
Cash	**$ 12**	$ 104
Accounts receivable and other	**1,087**	751
	1,099	855
Property, plant and equipment (net)	**15,931**	13,714
Deferred charges	**71**	74
	$ 17,101	$ 14,643
LIABILITIES		
Current liabilities		
Accounts payable	**$ 545**	$ 464
Accrued liabilities	**653**	582
Current portion of long-term debt (note 4)	**-**	184
Current portion of other long-term liabilities (note 5)	**534**	130
	1,732	1,360
Long-term debt (note 4)	**3,314**	2,645
Other long-term liabilities (note 5)	**1,117**	938
Future income tax (note 6)	**4,064**	3,591
	10,227	8,534
SHAREHOLDERS' EQUITY		
Preferred securities	**101**	103
Share capital (note 7)	**2,400**	2,353
Retained earnings	**4,372**	3,650
Foreign currency translation adjustment (note 8)	**1**	3
	6,874	6,109
	$ 17,101	$ 14,643

(1) Restated (note 2).

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Sep 30 2004**	Three Months Ended Sep 30 2003(1)	Nine Months Ended **Sep 30 2004**	Nine Months Ended Sep 30 2003(1)
Revenue	**$ 2,075**	$ 1,454	**$ 5,578**	$ 4,796
Less: royalties	**(276)**	(190)	**(756)**	(699)
Revenue, net of royalties	**1,799**	1,264	**4,822**	4,097
Expenses				
Production	**376**	307	**1,023**	921
Transportation	**63**	64	**179**	194
Depletion, depreciation and amortization	**453**	387	**1,268**	1,118
Asset retirement obligation accretion (note 5)	**14**	16	**35**	46
Administration	**31**	22	**81**	63
Stock-based compensation (note 5)	**120**	32	**233**	137
Interest	**45**	44	**134**	151
Risk management activities	**276**	11	**576**	165
Foreign exchange gain	**(93)**	(8)	**(28)**	(225)
	1,285	875	**3,501**	2,570
Earnings before taxes	**514**	389	**1,321**	1,527
Taxes other than income tax	**62**	29	**150**	81
Current income tax (recovery) expense (note 6)	**(8)**	25	**122**	83
Future income tax expense (note 6)	**153**	133	**219**	220
Net earnings	**307**	202	**830**	1,143
Dividend on preferred securities, net of tax	**(1)**	(1)	**(4)**	(4)
Revaluation of preferred securities, net of tax	**5**	-	**2**	14
Net earnings attributable to common shareholders	**$ 311**	$ 201	**$ 828**	$ 1,153
Net earnings attributable to common shareholders per common share (note 9)				
Basic	**$ 1.16**	$ 0.75	**$ 3.09**	$ 4.29
Diluted	**$ 1.13**	$ 0.74	**$ 3.07**	$ 4.14

(1) Restated (note 2).

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Nine Months Ended Sep 30 2004	Sep 30 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	**830**	1,143
Dividend on common shares (note 7)	**(80)**	(61)
Purchase of common shares (note 7)	**(26)**	(81)
Dividend on preferred securities, net of tax	**(4)**	(4)
Revaluation of preferred securities, net of tax	**2**	14
Balance – end of period	**$ 4,372**	$ 3,435

(1) Restated (note 2).

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2004	Three Months Ended Sep 30 2003(1)	Nine Months Ended Sep 30 2004	Nine Months Ended Sep 30 2003(1)
Operating activities				
Net earnings	**$ 307**	$ 202	**$ 830**	$ 1,143
Non-cash items				
Depletion, depreciation and amortization	**453**	387	**1,268**	1,118
Asset retirement obligation accretion	**14**	16	**35**	46
Stock-based compensation	**119**	32	**225**	137
Deferred petroleum revenue tax (recovery)	**(14)**	1	**(13)**	8
Unrealized risk management activities	**105**	-	**277**	-
Future income tax	**153**	133	**219**	220
Unrealized foreign exchange gain	**(94)**	(11)	**(15)**	(239)
Deferred charges	**4**	3	**3**	5
Abandonment expenditures	**(14)**	(14)	**(27)**	(20)
Net change in non-cash working capital	**110**	91	**(51)**	(89)
	1,143	840	**2,751**	2,329
Financing activities				
(Repayment) issue of bank credit facilities	**(138)**	(133)	**743**	(634)
Repayment of medium-term notes	**-**	-	**(125)**	-
Repayment of senior unsecured notes	**-**	(14)	**(54)**	(85)
Repayment of obligations under capital leases	**-**	(1)	**(7)**	(7)
Issue of common shares	**2**	4	**22**	83
Purchase of common shares	**(3)**	(58)	**(33)**	(123)
Dividend on common shares	**(27)**	(20)	**(74)**	(57)
Dividend on preferred securities	**(2)**	(2)	**(7)**	(7)
Net change in non-cash working capital	**6**	6	**2**	(2)
	(162)	(218)	**467**	(832)
Investing activities				
Business combination, net of cash acquired (note 3)	**-**	-	**(444)**	-
Expenditures on property, plant and equipment	**(861)**	(608)	**(2,718)**	(1,843)
Net proceeds on sale of property, plant and equipment	**-**	1	**4**	19
Net expenditures on property, plant and equipment	**(861)**	(607)	**(3,158)**	(1,824)
Net change in non-cash working capital	**(124)**	(3)	**(152)**	327
	(985)	(610)	**(3,310)**	(1,497)
(Decrease) increase in cash	**(4)**	12	**(92)**	-
Cash – beginning of period	**16**	18	**104**	30
Cash – end of period	**$ 12**	$ 30	**$ 12**	$ 30

(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:

	Nine Months Ended			
		Sep 30 2004		Sep 30 2003
Increase opening retained earnings	**$**	**6**	$	10
Decrease depletion, depreciation and amortization	**$**	**(64)**	$	(42)
Increase asset retirement obligation accretion	**$**	**35**	$	46
Increase (decrease) future income tax expense	**$**	**14**	$	(1)

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 designated certain of its derivative financial instruments (note 11) as hedges, including certain crude oil puts, 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:

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	$	643
Future income tax liability		(129)
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

		Sep 30 2004		Dec 31 2003
Bank credit facilities				
Bankers' acceptances	**$**	**387**	$	-
US dollar bankers' acceptances (2004 – US$471 million, 2003 – US$207 million)		**595**		268
Medium-term notes		**125**		250
Senior unsecured notes (2004 – US$218 million, 2003 – US$258 million)		**311**		366
US dollar debt securities (2004 – US$1,500 million, 2003 – US$1,500 million)		**1,896**		1,938
Obligations under capital leases		**-**		7
		3,314		2,829
Less: current portion of long-term debt		**-**		184
	$	**3,314**	$	2,645

Bank credit facilities

At September 30, 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 $22 million have been issued.

Medium-term notes

In May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 28, 2004.

Senior unsecured notes

In May 2004, the Company repaid the US$40 million 6.42% senior unsecured notes due May 27, 2004.

5. OTHER LONG-TERM LIABILITIES

		Sep 30 2004		Dec 31 2003
Asset retirement obligation	**$**	**1,057**	$	897
Stock-based compensation		**315**		171
Risk management		**247**		-
Deferred revenue		**32**		-
		1,651		1,068
Less: current portion		**534**		130
	$	**1,117**	$	938

Asset retirement obligation

At September 30, 2004, the Company's total estimated undiscounted costs to settle its asset retirement obligation with respect to crude oil and natural gas properties and facilities was $2,783 million (December 31, 2003 – $2,281 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:

	Nine Months Ended Sep 30, 2004	Year Ended Dec 31, 2003(1)
Asset retirement obligation		
Balance – beginning of period	**$ 897**	$ 867
Liabilities incurred	**287**	117
Liabilities settled	**(27)**	(40)
Asset retirement obligation accretion	**35**	62
Revision of estimates	**(112)**	(6)
Foreign exchange	**(23)**	(103)
Balance – end of period	**$ 1,057**	$ 897

(1) Effective January 1, 2004, the Company retroactively adopted CICA Handbook section 3110, "Asset Retirement Obligations" (note 2). The prior period balance of other long-term liabilities has 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 currently vested options and all options vesting during that period are surrendered for cash settlement.

	Nine Months Ended Sep 30, 2004	Year Ended Dec 31, 2003
Stock-based compensation		
Balance – beginning of period	**$ 171**	**$** -
Stock-based compensation provision	**233**	200
Current period expense relating to share bonus plan	**(8)**	-
Current period payment for options surrendered	**(66)**	(31)
Transferred to common shares	**(32)**	(8)
Capitalized with respect to Horizon Project	**17**	10
Balance – end of period	**315**	171
Less: current portion	**243**	130
	$ 72	**$** 41

Risk Management

On January 1, 2004, the fair values of all outstanding financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount (note 2). 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 – beginning of period	**$ 40**	**$ (40)**
Change in fair value of financial instruments	**-**	**287**
Amortization of deferred revenue	**(8)**	**-**
Fair value of financial instruments – end of period	**32**	**247**
Less: current portion	**21**	**270**
	$ 11	**$ (23)**

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Current income tax expense				
Current income tax – North America	**$ 6**	$ 12	**$ 88**	$ 40
Large corporations tax – North America	**2**	5	**6**	15
Current income tax (recovery) – North Sea	**(19)**	5	**18**	21
Current income tax – Offshore West Africa	**3**	3	**10**	7
	(8)	25	**122**	83
Future income tax expense	**153**	133	**219**	220
Income taxes	**$ 145**	$ 158	**$ 341**	$ 303

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, and accordingly, the Company's future income tax liability was reduced by $66 million in the first quarter. The legislation received royal assent in May 2004.

In the second quarter of 2003, the Alberta government introduced legislation to reduce the provincial corporate income tax rate by 0.5% and the Federal government introduced legislation to phase in over five years a reduction in corporate income tax rates, the elimination of the deduction for resource allowance, and the introduction of a deduction for crown charges. The Alberta and Federal corporate income tax changes resulted in a reduction of the future income tax liability of $31 million and $247 million respectively in the second quarter of 2003.

7. SHARE CAPITAL

Issued

Common shares	Nine Months Ended September 30, 2004 Number of shares (thousands)[1]		Amount
Balance – beginning of period	**267,463**	**$**	**2,353**
Issued upon exercise of stock options	**1,434**		**22**
Previously recognized liability on stock options exercised for common shares	**-**		**32**
Purchase of shares under Normal Course Issuer Bid	**(873)**		**(7)**
Balance – end of period	**268,024**	**$**	**2,400**

(1) Restated to reflect two-for-one share split in May 2004.

Share split

The Company's Shareholders approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2004. All common share and per common share amounts have been restated to retroactively reflect the share split.

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 13,380,770 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 September 30, 2004, the Company had purchased 873,400 common shares for a total cost of $33 million. The excess cost over the book value of the shares purchased was applied to retained earnings.

Dividend policy

On February 19, 2004, the Board of Directors set the regular quarterly dividend at $0.10 per common share (2003 - $0.075 per common share). The Company pays regular quarterly dividends in January, April, July, and October of each year.

Stock options

	Nine Months Ended September 30, 2004		
	Stock options (thousands)[1]		**Weighted average exercise price**[1]
Outstanding – beginning of period	**17,789**	**$**	**19.72**
Granted	**4,401**	**$**	**34.64**
Exercised for common shares	**(1,434)**	**$**	**15.52**
Surrendered for cash settlement	**(3,328)**	**$**	**18.55**
Forfeited	**(785)**	**$**	**27.14**
Outstanding – end of period	**16,643**	**$**	**23.91**
Exercisable – end of period	**3,623**	**$**	**19.43**

(1) Restated to reflect two-for-one share split in May 2004.

8. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain 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.

		Sep 30 2004
Balance – beginning of period as previously reported	**$**	**17**
Change in accounting policy (note 2)		**(14)**
Balance – beginning of period as restated		**3**
Unrealized loss on translation of net investment		**(9)**
Hedge of net investment with US dollar denominated debt (net of tax)		**7**
Balance – end of period	**$**	**1**

9. NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2004[(1)]	Sep 30 2003[(1)]	**Sep 30 2004[(1)]**	Sep 30 2003[(1)]
Weighted average common shares outstanding (thousands)				
Basic	**268,463**	269,512	**268,129**	268,670
Effect of dilutive stock options [(2)]	**-**	-	**-**	3,260
Assumed settlement of preferred securities with common shares	**2,310**	3,988	**2,542**	4,226
Diluted	**270,773**	273,500	**270,671**	276,156
Net earnings attributable to common shareholders	**$ 311**	$ 201	**$ 828**	$ 1,153
Dividend on preferred securities, net of tax	**1**	1	**4**	4
Revaluation of preferred securities, net of tax	**(5)**	-	**(2)**	(14)
Diluted net earnings attributable to common shareholders	**$ 307**	$ 202	**$ 830**	$ 1,143
Net earnings attributable to common shareholders per common share				
Basic	**$ 1.16**	$ 0.75	**$ 3.09**	$ 4.29
Diluted	**$ 1.13**	$ 0.74	**$ 3.07**	$ 4.14

(1) Restated to reflect two-for-one share split in May 2004.

(2) 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		Nine Months Ended	
	Sep 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Interest paid	**$ 54**	$ 45	**$ 150**	$ 147
Taxes paid				
Taxes other than income tax	**$ 53**	$ 20	**$ 124**	$ 9
Current income tax	**$ (6)**	$ 6	**$ 57**	$ 18

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 October 28, 2004, which includes all transactions outstanding at September 30, 2004:

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps	Oct 2004 – Dec 2004	40,000 bbl/d	US$1.22	Dated Brent/WTI
Oil price collars	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
	Apr 2005 – Jun 2005	30,000 bbl/d	US$29.00 – US$41.70	WTI
Oil puts	Oct 2004 – Dec 2004	20,000 bbl/d	US$27.00	WTI
	Jan 2005 – Mar 2005	119,000 bbl/d	US$30.73	WTI
	Apr 2005 – Jun 2005	143,000 bbl/d	US$30.57	WTI
	Jul 2005 – Sep 2005	75,000 bbl/d	US$32.70	WTI
	Oct 2005 – Dec 2005	50,000 bbl/d	US$29.81	WTI

	Remaining Term	Volume	Average Price	Index
Natural gas				
AECO collars	Oct 2004	400,000 GJ/d	C$5.00 – C$8.75	AECO
	Nov 2004 – Mar 2005	200,000 GJ/d	C$7.00 – C$13.88	AECO
	Nov 2004 – Oct 2005	300,000 GJ/d	C$6.00 – C$10.54	AECO

	Remaining Term	Amount ($ millions)	Average Exchange Rate (US$/C$)
Foreign currency			
Currency collars	Oct 2004 – Dec 2004	US$3/month	1.45 – 1.54
	Oct 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	Oct 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	Oct 2004	–	Jul 2006	US$200	6.70%	LIBOR + 1.65%
	Oct 2004	–	Jan 2005	US$200	7.20%	LIBOR + 3.00%
	Oct 2004	–	Jan 2007	US$200	7.20%	LIBOR + 2.23%
	Oct 2004	–	Oct 2012	US$350	5.45%	LIBOR + 0.81%
Swaps – floating to fixed	Oct 2004	–	Mar 2007	C$10	7.36%	CDOR

12. SEGMENTED INFORMATION

	Three Months Ended		Nine Months Ended	
	Sep 30 2004	Sep 30 2003	**Sep 30 2004**	Sep 30 2003
Revenue				
North America	**$ 1,604**	$ 1,163	**$ 4,432**	$ 3,952
North Sea	**403**	240	**959**	718
Offshore West Africa	**61**	46	**167**	106
Midstream	**17**	13	**50**	45
Intersegment elimination	**(10)**	(8)	**(30)**	(25)
	$ 2,075	$ 1,454	**$ 5,578**	$ 4,796
Net Earnings				
North America	**$ 274**	$ 146	**$ 674**	$ 987
North Sea	**(7)**	36	**71**	105
Offshore West Africa	**34**	15	**67**	32
Midstream	**6**	5	**18**	19
	307	202	**830**	1,143
Dividend on preferred securities, net of tax	**(1)**	(1)	**(4)**	(4)
Revaluation of preferred securities, net of tax	**5**	-	**2**	14
Net Earnings Attributable to Common Shareholders	**$ 311**	$ 201	**$ 828**	$ 1,153
Additions to Property, Plant and Equipment				
North America – business combination	**$ -**	$ -	**$ 645**	$ -
North America – crude oil and natural gas	**339**	407	**1,741**	1,338
North Sea	**385**	109	**536**	257
Offshore West Africa	**54**	53	**185**	129
Horizon Oil Sands Project	**84**	32	**233**	100
Midstream	**2**	5	**5**	9
Head office	**12**	10	**27**	15
	$ 876	$ 616	**$ 3,372**	$ 1,848

	Property, Plant and Equipment		Total Assets	
	Sep 30 2004	Dec 31 2003	**Sep 30 2004**	Dec 31 2003
Segmented Assets				
North America	**$ 12,404**	$ 10,990	**$ 13,324**	$ 11,731
North Sea	**1,849**	1,437	**2,045**	1,562
Offshore West Africa	**810**	667	**839**	703
Horizon Oil Sands Project	**614**	381	**614**	381
Midstream	**199**	200	**224**	227
Head office	**55**	39	**55**	39
	$ 15,931	$ 13,714	**$ 17,101**	$ 14,643

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 September 30, 2004:	
Interest coverage (times)	
Net earnings(1)	10.2x
Cash flow from operations(2)	23.0x

(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 September 30, 2004, would be 9.7x and the cash flow coverage ratio for the 12-month period ended September 30, 2004 would be 21.9x.

Officers

Allan P. Markin
Chairman

N. Murray Edwards
Vice-Chairman

John G. Langille
President

Steve W. Laut
Chief Operating Officer

Réal M. Cusson
Senior Vice-President, Marketing

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

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

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

Douglas A. Proll
Senior Vice-President, Finance

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeffrey W. Wilson
Senior Vice-President, Exploration

Bruce E. McGrath
Corporate Secretary

Mary-Jo E. Case
Vice-President, Land

Wayne M. Chorney
Vice-President, Development Operations

William R. Clapperton
Vice-President, Regulatory, Stakeholder & Environmental Affairs

Gordon M. Coveney
Vice-President, Exploration – East

Randall S. Davis
Vice-President, Financial Accounting & Controls

Jerome W. Harvey
Vice-President, Commercial Operations

Terry J. Jocksch
Vice-President, Exploitation – East

Cameron S. Kramer
Vice-President, Field Operations

León Miura
Vice-President, Upgrading – Oil Sands

John S. J. Parr
Vice-President, Production – East

David A. Payne
Vice-President, Exploitation – West

William R. Peterson
Vice-President, Production – West

John C. Puckering
Vice-President, Site Development – Oil Sands

Sheldon L. Schroeder
Vice-President, Project Control – Oil Sands

Kendall W. Stagg
Vice-President, Exploration – West

Lynn M. Zeidler
Vice-President, Bitumen Production – Oil Sands

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ and CNQ.U*

*denotes trading in US funds

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

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Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Board of Directors

Catherine M. Best

N. Murray Edwards

Ambassador Gordon D. Giffin

John G. Langille

Keith A.J. MacPhail

Allan P. Markin

Honourable Frank McKenna, P.C., O.N.B., Q.C.

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

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David A. Tuer

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