CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY AND ANNUAL EARNINGS, 2004 RESULTS AND RESERVES

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In commenting on fourth quarter and year-end 2004 results, Canadian Natural's Chairman, Allan Markin, stated "As the Company embarks on the construction of the Horizon Oil Sands Project, record annual daily production of 514,000 barrels of oil equivalent per day combined with strong commodity prices enabled us to achieve record annual earnings and cash flows in 2004. Daily production grew 12% in 2004, above our internal target of 10%. In fact we showed positive returns in each of our other per share value creation metrics this past year with net proved and probable reserves up 16%, production up 13%, cash flow up 19% and Net Asset Value up 39%. These results are attributable to the hard work and dedication of our people and the strong asset base the Company has developed over time through organic growth and accretive acquisitions."

"As we move forward into 2005, we look to our strong project inventory of natural gas and crude oil assets in Canada, the North Sea and Offshore West Africa, which includes Baobab, Primrose, and West Espoir, to continue that growth profile as we transform Canadian Natural into one of the most sustainable independent energy companies in the world. As we do this, we remain committed, to adding shareholder value by controlling both operating and capital costs, doing it right and working together."

Canadian Natural's President, John Langille, in commenting on the financial results added "Continued focus on cost control and execution of our defined plan has enabled us to deliver record quarterly and annual earnings of $577 million and $1.4 billion respectively and record annual cash flow of $3.8 billion. These results were achieved in an environment of high fourth quarter differentials for heavy crude oil and a rising Canadian dollar during the year. Our balance sheet is strong as we commence development on the Horizon Oil Sands Project with a debt to book capitalization ratio of 34% and debt to cash flow at 1.0 times. This was only possible as a result of financial discipline and capital reallocation that was undertaken as we completed four strategic acquisitions during 2004. This discipline is further evidenced by the increased hedging position for 2005 and 2006 which will ensure strong cash flows during the upcoming capital intensive years as the construction of Horizon proceeds."

Canadian Natural's Chief Operating Officer, Steve Laut, in commenting on the Company's reserves stated "We were able to replace 220% of our conventional production with new proved reserves of conventional crude oil and natural gas during 2004. As a result of our successful drilling and exploitation programs 69% of these additions were achieved through the drill bit while 31% was from accretive acquisitions. These increases in conventional reserves were replaced at an attractive finding and onstream cost of $12.03 per barrel of oil equivalent on a net proved basis, 3% lower than our 2003 costs, despite overall increasing industry costs as a result of record levels of industry activity. These reduced costs reflect Canadian Natural's strong asset base and disciplined approach. In addition to these conventional reserves, Canadian Natural, commensurate with the Board of Directors sanctioning of the project on February 9, 2005, booked 3.3 billion barrels of proved and probable bitumen mining reserves at the Horizon Oil Sands Project that will be upgraded on-site into light sweet synthetic crude oil. The Horizon Project will add significant free cash flow for the Company."

HIGHLIGHTS

- Record annual net earnings of $1.4 billion ($5.24 per common share), comparable to the $1.4 billion ($5.23 per common share) in 2003. Record adjusted net earnings from operations amounted to $1.4 billion ($5.24 per common share) compared with $1.0 billion ($3.68 per common share) in 2003.

- Record annual cash flow of $3.8 billion ($14.06 per common share), compared with $3.2 billion ($11.77 per common share) in 2003.

- Record quarterly net earnings of $577 million ($2.15 per common share), compared with $250 million ($0.93 per common share) for Q4/2003 and $311 million ($1.16 per common share) in Q3/2004. Adjusted net earnings from operations, a non Generally Accepted Accounting Principle ("GAAP") term used by the Company to judge its operational performance, amounted to $321 million ($1.20 per common share) compared with $194 million ($0.72 per common share) for Q4/2003 and $381 million ($1.42 per common share) in Q3/2004.

- Quarterly cash flow of $950 million ($3.54 per common share) compared with $734 million ($2.74 per common share) in Q4/2003 and $1,041 million ($3.88 per common share) in Q3/2004.

- Record annual equivalent production of 514 mboe/d before royalties (440 mboe/d net of royalties), an increase of 12% over 2003. Quarterly equivalent production of 531 mboe/d before royalties (457 mboe/d net of royalties), represents the fifth consecutive quarter of overall production growth and a 16% increase over Q4/2003.

- Quarterly crude oil and NGLs production of 296 mbbl/d before royalties (268 mbbl/d net of royalties). This represents an increase of 21% over Q4/2003 production and less than a 1% decrease from Q3/2004 production.

- Quarterly natural gas sales of 1,410 mmcf/d before royalties (1,137 mmcf/d net of royalties), representing 44% of equivalent production during the quarter. This represents an 11% increase over Q4/2003 production and a 1% increase over Q3/2004 production.

- Completed the acquisition of Western Canadian Core Properties effective December 1, 2004, adding approximately 25 mboe/d of production to the Company's production base and 510,000 net acres of undeveloped land.

- Fourth quarter capital expenditures of $1.4 billion, reflecting increased fourth quarter drilling activities and the previously noted acquisition of Western Canadian Core Properties.

- During the quarter, Canadian Natural drilled 273 net wells, excluding strat/service wells, with a 95% success ratio, reflecting Canadian Natural's low risk asset base.

- Net undeveloped land base in Canada increased 17% in 2004 to 11.5 million net acres.

- Using independent qualified reserve evaluators' determinations of the Company's conventional oil and natural gas reserves under constant prices as at December 31, 2004:

    - Total net proved reserves after royalties, from conventional operations at the end of 2004 amounted to 1.1 billion barrels of crude oil and NGLs and 2.7 trillion cubic feet of natural gas with proved and probable reserves of 1.5 billion barrels of crude oil and NGLs and 3.5 trillion cubic feet of natural gas.

    - Net proved reserve additions from conventional operations equaled 220% of 2004 production, at a finding and onstream cost of $12.03 per barrel of oil equivalent. Achieved natural gas reserve additions of 0.5 trillion cubic feet, 100% of which are located in North America. Achieved crude oil and NGLs reserve additions of 265 mmbbl or 282% of 2004 crude oil production.

    - Net proved and probable reserve additions from conventional operations equaled 281% of 2004 production, at a finding and onstream cost of $9.40 per barrel of oil equivalent. Achieved natural gas reserve additions of close to 0.8 trillion cubic feet, bringing total proved and probable natural gas reserves to 3.5 trillion cubic feet, 96% of which are located in North America. Achieved crude oil and NGLs reserve additions of 324 mmbbl or 345% of 2004 crude oil production.

    - Using net proved and probable reserve additions the Company achieved an overall recycle ratio of 2.7 (2.1 using only proved reserve additions) during 2004.

- The Company's financial position remained strong as debt to book capitalization was 34% at the end of 2004 compared to 33% at the end of 2003. Debt to cash flow at the end of 2004 was 1.0 times compared to 0.9 times at the end of 2003.

- Horizon Oil Sands Project received project sanction from Canadian Natural's Board of Directors on February 9, 2005. As a result of the sanctioning the Company recorded 1.9 billion barrels of proved bitumen mining reserves before royalties and 3.3 billion barrels of proved and probable bitumen mining reserves before royalties for the Horizon Oil Sands Project as determined by independent qualified reserves evaluators Gilbert Laustsen Jung Associates Ltd. ("GLJ").

- Under its Normal Course Issuer Bid, the Company purchased 873,400 of its common shares during 2004 for a total cost of $33 million (average cost - $38.01 per share).

- Fifth straight year of dividend increases. The 2005 quarterly dividends will increase 12.5% from $0.10 per common share to $0.1125 per common share commencing with the April 1, 2005 dividend payment.

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			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Net earnings as reported	**$ 577**	$ 311	$ 250	**$ 1,405**	$ 1,403
Unrealized foreign exchange gain[(1)]	**(61)**	(80)	(68)	**(75)**	(274)
Unrealized risk management (gain) loss[(2)]	**(212)**	70	-	**(27)**	-
Effect of statutory tax rate changes on future income tax liabilities[(3)]	**-**	-	(31)	**(66)**	(278)
Stock-based compensation expense[(4)]	**17**	80	43	**168**	136
Adjusted net earnings from operations	**$ 321**	$ 381	$ 194	**$ 1,405**	$ 987
Per share – basic[(5)]	**$ 1.20**	$ 1.42	$ 0.72	**$ 5.24**	$ 3.68
– diluted[(5)]	**$ 1.18**	$ 1.41	$ 0.72	**$ 5.20**	$ 3.61

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

(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, the province of Alberta 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, the province of Alberta introduced legislation to reduce its corporate income tax rate.

(4) The Company's employee stock option plan provides 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 net 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.

Overall equivalent fourth quarter production represents a slight increase over Q3/2004 and an increase of 16% over Q4/2003. Total quarterly and annual production of both natural gas and crude oil and NGLs were within guidance parameters previously announced.

Crude oil and NGLs production for the year ended December 31, 2004 averaged 282 mbbl/d, representing an increase of 17% over 2003, while natural gas averaged 1,388 mmcf/d, an increase of 7% compared to the previous year. On a barrel of oil equivalent basis, overall daily production increased 12% year over year.

Natural gas production levels in Q4/2004 represented an increase of 1% over the previous quarter and 11% over the prior year. Increased fourth quarter production reflects a more active, but weather constrained, fall drilling program in North America for natural gas as compared to previous years as well as the impact of accretive acquisitions.

Crude oil and NGLs production during Q4/2004 averaged 296 mbbl/d, consistent with Q3/2004 and a 21% increase over Q4/2003, reflecting a successful 2004 drilling program and accretive acquisitions.

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

	Q4 2004		Q3 2004		Q4 2003	
	mboe/d	**%**	mboe/d	%	mboe/d	%
Natural gas	**235.0**	**44**	232.7	44	211.7	46
Light crude oil and NGLs	**129.2**	**24**	128.8	24	115.4	25
Pelican Lake crude oil	**19.1**	**4**	21.0	4	21.5	5
Primary heavy crude oil	**93.7**	**18**	96.3	18	71.0	16
Thermal heavy crude oil	**53.7**	**10**	51.1	10	36.4	8
Total	**530.7**	**100**	529.9	100	456.0	100

The Company currently expects 2005 production levels before royalties to average 1,448 to 1,510 mmcf/d of natural gas and 307 to 335 mbbl/d of crude oil and NGLs. First quarter 2005 production guidance before royalties for natural gas is 1,440 to 1,482 mmcf/d of natural gas and 269 to 290 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)

	Year Ended December 31			
	2004		2003	
	Gross	**Net**	Gross	Net
Crude oil	**378**	**328**	490	458
Natural gas	**801**	**689**	841	777
Dry	**106**	**96**	126	118
Subtotal	**1,285**	**1,113**	1,457	1,353
Stratigraphic test / service wells	**339**	**336**	447	440
Total	**1,624**	**1,449**	1,904	1,793
Success rate (excluding stratigraphic test / service wells)		**91%**		91%

During the quarter, Canadian Natural drilled a total of 333 net wells, including 60 stratigraphic test and service wells. Canadian Natural drilled 162 net wells targeting natural gas, including 56 wells in North Alberta, 54 wells in South Alberta targeting shallow gas, 42 wells in Northwest Alberta and 10 wells in Northeast British Columbia. This program reflected a planned earlier start to the conventional winter drilling program which was partially delayed due to wet conditions caused by mild weather for winter only access locations. The early start to the winter drilling program reflects Canadian Natural's ability to utilize inventory and achieve cost control by starting the program earlier and using fewer overall rigs which enhances overall capital efficiency.

The Company also drilled 107 net wells targeting crude oil during the fourth quarter 2004. These wells were concentrated in the Company's crude oil region of North Alberta where 90 wells targeting heavy crude oil were drilled. This included 13 high-pressure thermal crude oil wells that were drilled and completed at Primrose as part of the 2004 development strategy for the area.

Total wells drilled in 2004 were down 18% when compared to 2003 as a result of the disciplined reallocation of capital that resulted following four strategic acquisitions completed during 2004. Also in 2004, the Company drilled 336 net stratigraphic test/service wells on the oil sands leases in the Horizon Oil Sands Project and in North Alberta.

The total success rate for Canadian Natural's drilling program was 95% for the quarter and 91% for 2004, 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 low risk asset base.

Pricing

Detailed reviews of benchmark pricing and sensitivity to product pricing, currency exchange, and interest rates are provided in Management's Discussion and Analysis. Product pricing for natural gas remained very strong during the fourth quarter as the company realized $6.77 per mcf, an increase of 8% from Q3/2004 and 29% over Q4/2003. This helped natural gas contribute to 47% of overall corporate revenue during the fourth quarter and average 46% during the year.

Benchmark product pricing for crude oil remained strong during the fourth quarter however heavy crude oil differentials and a strong Canadian dollar negatively impacted realized pricing when compared to Q3/2004. Heavy oil differentials increased 56% from Q3/2004 levels to US$19.61 in Q4/2004 as a result of physical limitations for demand at refineries due to plant turnarounds and maintenance which exacerbated the impact of normal seasonality. Additional issues at refineries and upgraders as well as the higher prices of diluents, required to reduce the viscosity of heavy oil production to meet requirements for transmission in sales pipelines, have significantly reduced the realizable value for bitumen in the month of December 2004 and January 2005, however the Company believes that these are short-term aberrations in the market and do not represent a fundamental change to the market for bitumen. Heavy oil differentials have already reduced from the highs reached in late December and similarly the cost of diluent is lowering. The Company's realized average crude oil and NGLs price of $36.92 for Q4/2004 represented a decrease of 15% compared to Q3/2004, however it represents an increase of 25% compared to Q4/2003.

While 2004 West Texas Intermediate ("WTI"), benchmark pricing for crude oil was US$41.43/bbl, 34% higher than the US$31.02/bbl average in 2003, a portion of this benefit was offset by a much stronger Canadian dollar. This same benchmark as measured in Canadian dollars averaged C$53.80.bbl in 2004, 23% higher than the C$43.69/bbl averaged in 2003. As noted above, heavy oil differentials expressed as a percentage of WTI also widened during 2004. In 2004 this differential averaged 32% versus 28% in 2003. The result of these offsetting factors was that the Company's 2004 average realized crude oil price was C$37.99/bbl up 16% from the C$32.66/bbl in 2003. Company average natural gas prices in 2004 were C$6.50/mcf, up 5% from the C$6.21 recorded in 2003, effectively reflecting higher benchmark NYMEX pricing offset by the strength in the Canadian dollar.

As part of an industry initiative to develop new blends of western Canadian crude oils, Canadian Natural, effective December 1, 2004 has blending capacity of up to 140 mbbl/d. The Company is currently contributing 123 mbbl/d of heavy blends to the Western Canadian Select ("WCS") stream which is a new blend of up to 10 different crude oil streams. WCS resembles a Bow River type of crude with distillation cuts approximating a natural heavy oil with premium quality asphalt characteristics. The new blend has an API of 19-22 degrees and is expected to grow from the current 240 mbbl/d and has the potential to become a new benchmark for North American markets, in addition to WTI. Both key benchmarks currently recognized by the market, WTI and Brent (North Sea) are showing significant declines in quantity.

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 12 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.

In an effort to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow through the Horizon Project construction period, the Board of Directors of the Company, in January 2005, authorized an expanded hedging program for Canadian Natural. This expanded program allows for up to 75% of the near 12 months estimated production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in years 3 and 4 to be hedged. This revised hedging program allows the Company to have greater stability to its free cash flow and enhances the Company's financial flexibility during the Horizon Project construction years. The Company currently has collar hedges covering approximately 71% and 45% of estimated 2005 and 2006 crude oil production respectively. Similarly, approximately 67% and 35% of estimated 2005 and 2006 natural gas production have been hedged. Details of these hedge positions, including floor and ceiling prices are available on the Company's website at www.cnrl.com/investor_info/corporate_guidance/hedging.html

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at Dec 31 2004	Drilling Activity Year ended Dec 31, 2004
	(thousands of net acres)	(net wells)
Northeast British Columbia	**2,040**	**192**
Northwest Alberta	**1,660**	**156**
North Alberta	**6,922**	**613**
South Alberta	**661**	**240**
Southeast Saskatchewan	**123**	**13**
Horizon Oil Sands Project	**117**	**218**
United Kingdom North Sea	**565**	**14**
Offshore West Africa	**886**	**3**
	12,974	**1,449**

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 fourth quarter was within guidance levels and averaged 1,365 mmcf/d, an increase of 2% or 29 mmcf/d from Q3/2004 and 13% or 159 mmcf/d from Q4/2003. Total year production volumes averaged 1,330 mmcf/d up 7% or 85 mmcf/d from 2003. Approximately half of the increase from the prior year reflects organic growth with the remainder representing accretive property acquisitions. Overall North American natural gas exit to exit rates increased 17% or 210 mmcf/d, of which 5% was organic and 12% was attributable to accretive acquisitions.

The Company's exploitation of the Cardium resources in Northwest Alberta continued with 18 new wells being drilled with a 100% success rate.

During the fourth quarter of 2004, Canadian Natural had increased capital spending levels directed toward natural gas drilling in an effort to reduce pressures of a tight 2005 winter drilling season by starting earlier. This effort included a detailed and sequential drilling program that facilitated 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. Through this process, Canadian Natural will use about 10 fewer drill rigs this year while drilling a similar number of wells during the winter season. Certain portions of this drill program were delayed due to warmer than expected weather through mid-December, however, as a result of contingency planning built into this plan the Company still expects to complete the majority of this original plan.

North American Crude Oil and NGLs

Canadian Natural's North American crude oil and NGLs production averaged 214 mbbl/d in Q4/04, essentially unchanged from Q3/2004 and up 22% from Q4/2003. Total year production averaged 206 mbbl/d in 2004, up 31 mbbl/d or 18% from 2003 levels. These year over year results were attributable to increases in production from the Primrose thermal oil facility expansion and increased light oil as a result of the acquisition of assets completed in December.

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 fourth quarter, the Company drilled 77 heavy crude oil wells and 13 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 from two new phases commenced in mid-2004 at 19,000 bbl/d, which was higher than the budgeted 13,000 bbl/d and resulted in in-situ production increasing to 54 mbbl/d, up 5% and 48% from Q3/2004 and Q4/2003 respectively. This better than expected production significantly enhances the economics of these pads and is a positive indicator for future pads to be drilled. Production from these pads is subject to the cycling of steam injection and crude oil production; therefore, due to such normal cycling activities, average production levels in Q1/2005 will be lower than Q4/2004. 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.

At Pelican Lake, the promising waterflooding test program continues and will be expanded to additional lands in the area. In addition, the Company will be pilot testing the use of a polymer flood on a portion of the field in an effort to further enhance field recoveries. This polymer flood pilot will commence during 2005 with a three injector, five producer pilot program.

Horizon Oil Sands Project

The Board of Directors unanimously authorized management to proceed with Phase 1 of the Horizon Oil Sands Project ("Horizon Project") on February 9, 2005 which is comprised of a bitumen mining operation and an onsite upgrader. This decision reflected the high degree of project definition that has enabled the Company to obtain approximately 68% of Phase 1 costs on a fixed price basis. To further mitigate the risks associated with fixed price bidding, the Phase 1 construction efforts were broken down into 21 individual projects, each with a value ranging from $10 million to $700 million.

The high degree of up front project engineering and pre-planning will also reduce the risks on cost plus aspects of the project and will mitigate the risk of scope changes on the fixed bid portions. The pre-engineering and lessons learned from our predecessors have also enabled the Company to prepare a detailed development and logistical plan to reduce the scheduling risk. Geological risk is low on the leases included in the Horizon Project as over 16 delineation wells have been drilled per section. Finally, technology risk is low as the Company is using existing proven technologies for both the extraction and upgrading processes.

Total expected capital costs for all three phases of the development are $10.8 billion. Capital costs for the first phase of the Horizon Project will be, including a contingency fund of $700 million, $6.8 billion with $1.4 billion incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion incurred in 2006, 2007 and 2008 respectively. When the Horizon Project is fully commissioned, operating costs, including sustaining capital, are expected to be in the range of $14.00 to $14.25 per barrel.

As a result of the Board of Directors approval of the first phase of the Horizon Project, independent qualified reserve evaluators, Gilbert Laustsen Jung Associates Ltd., evaluated the leases associated with the Horizon Oil Sands Project and assigned 3.3 billion barrels of proved and probable bitumen reserves before royalties. These reserves were evaluated under SEC Industry Guide 7 and included in the Company's mining reserves effective February 9, 2005.

Current activity at the site includes site preparation, installation of deep undergrounds and construction of onsite access roads, and construction camps. Canadian Natural currently is utilizing the services of 1,280 people working on the Horizon Project; including 330 people on site, 350 employees in its Calgary office and an additional 600 people employed by engineering firms working together on the effective execution of the project.

North Sea

Canadian Natural continues to utilize its mature basin expertise, and will continue to target accretive acquisitions with exploitation upside potential in the North Sea. Quarterly crude oil production of 70 mbbl/d was less than expected primarily due to an unplanned extended shutdown on a Ninian platform. The shutdown was required to repair a power turbine used to drive water injection resulting in a loss of pressure to the reservoir. Remedial work has now been completed and with water injection back to capacity, production is recovering. During the quarter, one production and one injection well were completed on the Columba B terrace. At Murchison, production commenced from the satellite pool, Playfair, at rates in excess of 5 mbbl/d of crude oil, and with sufficient associated natural gas to provide the Murchison platform’s energy needs, thereby reducing operating costs.

Canadian Natural completed the gas reinjection project at the Banff Field in the Central North Sea commencing in November 2004. This project will ultimately increase overall reservoir recovery by approximately 17 mmbbl net to Canadian Natural, but has resulted in reductions in natural gas production and sales of approximately 30 mmcf/d. Despite some delays and production interruptions during commissioning, results to date are positive with full production benefit expected to commence during the second quarter of 2005.

Following the successful completion of the T & B Block acquisition, Canadian Natural will embark on a program of infill drilling, workovers and third party business during 2005. The Tiffany platform drilling rig is undergoing major refurbishment in order to undertake a three well program. On Thelma, two wells are scheduled to spud later this year targeting unswept areas of the field, using a semi submersible drilling unit. At Balmoral, Canadian Natural is undertaking a reservoir re-evaluation program and has acquired exploration acreage in the vicinity of the Balmoral Floating Production vessel.

Offshore West Africa

The development of Canadian Natural’s 57.61% owned and operated Baobab Field, located offshore Côte d’Ivoire continued on time and on budget. The Baobab Floating Production Storage and Offtake (“FPSO”) vessel was completed during the fourth quarter and is now moored on location. The installation of subsea equipment and pipelines commenced during the quarter and is progressing for first production, expected mid 2005. Wells drilled, completed and tested to date continue to meet or exceed delivery expectations. Initial production rates of approximately 25 mbbl/d net to Canadian Natural are expected by mid year, subsequently increasing to approximately 35 mbbl/d in the first half of 2006.

Production at East Espoir continues to meet expectations, averaging 12 mboe/d, net to Canadian Natural, during the fourth quarter. To facilitate the drilling of 4 additional (2.3 net) infill wells in East Espoir and modifications to the Espoir FPSO to accommodate West Espoir, production will be shut in for three weeks during the first quarter of 2005 resulting in approximately 4 mboe/d of curtailed production in the first quarter of 2005. A drilling tower is also under construction, progressing on time and within budget, and will be installed at West Espoir in order to facilitate development drilling. First oil from West Espoir is expected in mid 2006 delivering 13 mboe/d when fully commissioned.

During the fourth quarter, the Acajou North exploration well was drilled to delineate the extent of the previously drilled Acajou discovery. However, the results did not yield sufficient hydrocarbons to merit a stand alone development at Acajou. This field is being evaluated for future tie-back to East Espoir. At Zaizou, an exploration well spudded late in the fourth quarter was unsuccessful and the data obtained from this well is currently being used in order to trace the pattern of oil migration in the area to help identify future exploration targets.

YEAR-END RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS

Canadian Natural retains qualified independent reserve evaluators, Sproule Associates Limited (“Sproule”), and Ryder Scott Company (“Ryder Scott”), to evaluate 100% of the Company’s proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company’s total reserves. Sproule evaluated the North American assets and Ryder Scott evaluated the international assets and a portion of the North American assets. Canadian Natural has been granted an exemption from the National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission (“SEC”) requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose proved and probable reserves and future net revenues using forecast prices and costs. Canadian Natural has elected to disclose proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information. Another difference between the two standards is in the definition of proved reserves however, as discussed in the Canadian Oil and Gas Evaluation Handbook (“COGEH”), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

Canadian Natural has significant oil reserves that are considered heavy with a gravity of less than 20 degrees. Heavy crude oil sells at a discount to light crude oils using the benchmark West Texas Intermediate, which has an API gravity of approximately 40 degrees, because it requires upgrading before it can be processed by conventional refineries. There is a finite capacity for upgrading in North America, which is often reached when heavy crude oil from other countries enters the North American market. Heavy crude oil requires blending with condensate or light synthetic crude oil (“diluent”) in order for it to be transported in a pipeline. During the winter, heavy crude oil requires a higher proportion of diluent because of the cold temperatures. Heavy crude oil is also processed into asphalt, which is typically in demand during the spring to fall paving months.

As a result of these factors, prices for heavy crude oil are historically low in December. Exacerbating this trend was reduced demand for heavy crude oil due to refinery turnarounds and other operational issues. During 2004 the price of heavy crude oil averaged US$30.40 per barrel but on December 31, 2004, the date the Company’s oil and natural gas reserves were evaluated, the calculated price of Hardisty 12 degree API heavy crude oil was less. As a result, 30 mmbbl of net proved heavy crude oil reserves did not produce positive cash flow and, in accordance with SEC regulations, were debooked. Notwithstanding the economics at December 31, 2004, the current price of heavy crude oil has returned to a price sufficient to return the reserves subtracted by negative revision to the proved reserve category.

The Board of Directors of the Company has a Reserves Committee, which has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ as to the Company’s reserves.

Horizon oil sands mining reserves are not part of Canadian Natural’s year-end reserves disclosure. Horizon reserves were evaluated as at February 9, 2005. Gilbert Laustsen Jung Associates Ltd. (“GLJ”), an independent qualified reserves evaluator was retained by the Reserves Committee of Canadian Natural’s Board of Directors to evaluate reserves associated with the Horizon Project incorporating both the mining and upgrading projects. These reserves were evaluated under SEC Industry Guide 7 and are discussed separately in this report.

RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES[1]

	December 31, 2004			
	Proved Developed[2]	**Proved Undeveloped[2]**	**Proved Total[2]**	**Proved and Probable[3]**
Crude Oil & NGLs (mmbbl)				
North America	**367**	**281**	**648**	**926**
North Sea	**218**	**85**	**303**	**415**
Offshore West Africa	**20**	**95**	**115**	**196**
	605	**461**	**1,066**	**1,537**
Natural Gas (bcf)				
North America	**2,213**	**378**	**2,591**	**3,319**
North Sea	**12**	**15**	**27**	**57**
Offshore West Africa	**5**	**67**	**72**	**90**
	2,230	**460**	**2,690**	**3,466**
Total Reserves (mmboe)	**976**	**538**	**1,514**	**2,115**
Reserve Replacement Ratio[4] (%)			**220**	**281**
Cost to Develop[5] ($/boe)				
10% discount	**0.85**	**3.58**	**1.77**	**1.78**
15% discount	**1.33**	**3.27**	**1.58**	**1.56**
Present Value of Reserves[6] ($ millions)				
10% discount	**13,739**	**4,399**	**18,138**	**22,938**
15% discount	**11,839**	**3,440**	**15,279**	**18,804**

RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES[1]

	December 31, 2003			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude Oil & NGLs (mmbbl)				
North America	348	240	588	857
North Sea	138	84	222	317
Offshore West Africa	23	62	85	133
	509	386	895	1,307
Natural Gas (bcf)				
North America	2,140	286	2,426	2,919
North Sea	46	16	62	102
Offshore West Africa	12	52	64	72
	2,198	354	2,552	3,093
Total Reserves (mmboe)	875	445	1,320	1,823
Reserve Replacement Ratio[4] (%)			129	308
Cost to Develop[5] ($/boe)				
10% discount	0.24	4.02	1.51	1.60
15% discount	0.22	3.69	1.39	1.44
Present Value of Reserves[6] ($ millions)				
10% discount	13,080	3,037	16,117	20,167
15% discount	11,222	2,273	13,495	16,460

CONVENTIONAL CRUDE OIL AND NGLs RESERVES RECONCILIATION[1] (mmbbl, net of royalties)

	North America	North Sea	Offshore West Africa	Total
Proved Reserves				
Reserves, December 31, 2002	**571**	**202**	**75**	**848**
Extensions & discoveries	1	-	13	14
Infill drilling	54	-	-	54
Improved recovery	9	-	-	9
Property purchases	7	27	-	34
Property disposals	-	-	-	-
Production	(56)	(21)	(4)	(81)
Revisions of prior estimates	2	14	1	17
Reserves, December 31, 2003	**588**	**222**	**85**	**895**
Extensions & discoveries	**17**	**-**	**-**	**17**
Infill drilling	**24**	**35**	**-**	**59**
Improved recovery	**1**	**10**	**-**	**11**
Property purchases	**36**	**38**	**-**	**74**
Property disposals	**-**	**-**	**-**	**-**
Production	**(66)**	**(24)**	**(4)**	**(94)**
Revisions of prior estimates	**48**	**22**	**34**	**104**
Reserves, December 31, 2004	**648**	**303**	**115**	**1,066**

	North America	North Sea	Offshore West Africa	Total
Proved and Probable Reserves				
Reserves, December 31, 2002	**636**	**277**	**121**	**1,034**
Extensions & discoveries	1	-	17	18
Infill drilling	58	-	-	58
Improved recovery	25	-	12	37
Property purchases	10	33	-	43
Property disposals	-	-	-	-
Production	(56)	(21)	(4)	(81)
Revisions of prior estimates	183	28	(13)	198
Reserves, December 31, 2003	**857**	**317**	**133**	**1,307**
Extensions & discoveries	**20**	**-**	**-**	**20**
Infill drilling	**29**	**49**	**-**	**78**
Improved recovery	**2**	**10**	**-**	**12**
Property purchases	**49**	**49**	**-**	**98**
Property disposals	**-**	**-**	**-**	**-**
Production	**(66)**	**(24)**	**(4)**	**(94)**
Revisions of prior estimates	**35**	**14**	**67**	**116**
Reserves, December 31, 2004	**926**	**415**	**196**	**1,537**

CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION[1] (bcf, net of royalties)

Proved Reserves	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2002	**2,446**	**71**	**71**	**2,588**
Extensions & discoveries	58	-	6	64
Infill drilling	243	-	-	243
Improved recovery	8	-	-	8
Property purchases	50	19	-	69
Property disposals	(3)	-	-	(3)
Production	(355)	(17)	(3)	(375)
Revisions of prior estimates	(21)	(11)	(10)	(42)
Reserves, December 31, 2003	**2,426**	**62**	**64**	**2,552**
Extensions & discoveries	**334**	**-**	**-**	**334**
Infill drilling	**74**	**-**	**-**	**74**
Improved recovery	**6**	**-**	**-**	**6**
Property purchases	**182**	**10**	**-**	**192**
Property disposals	**(8)**	**-**	**-**	**(8)**
Production	**(383)**	**(18)**	**(3)**	**(404)**
Revisions of prior estimates	**(40)**	**(27)**	**11**	**(56)**
Reserves, December 31, 2004	**2,591**	**27**	**72**	**2,690**

Proved and Probable Reserves				
Reserves, December 31, 2002	**2,765**	**89**	**90**	**2,944**
Extensions & discoveries	72	-	11	83
Infill drilling	285	-	-	285
Improved recovery	26	-	(6)	20
Property purchases	59	22	-	81
Property disposals	(3)	-	-	(3)
Production	(355)	(17)	(3)	(375)
Revisions of prior estimates	70	8	(20)	58
Reserves, December 31, 2003	**2,919**	**102**	**72**	**3,093**
Extensions & discoveries	**418**	**-**	**-**	**418**
Infill drilling	**106**	**-**	**-**	**106**
Improved recovery	**6**	**-**	**-**	**6**
Property purchases	**236**	**18**	**-**	**254**
Property disposals	**(10)**	**-**	**-**	**(10)**
Production	**(383)**	**(18)**	**(3)**	**(404)**
Revisions of prior estimates	**27**	**(45)**	**21**	**3**
Reserves, December 31, 2004	**3,319**	**57**	**90**	**3,466**

The following information for reserves before royalties is provided for comparative purposes:

CONVENTIONAL RESERVES, BEFORE ROYALTIES[1]

December 31, 2004	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude Oil & NGLs (mmbbl)				
North America	**399**	**296**	**695**	**992**
North Sea	**218**	**85**	**303**	**415**
Offshore West Africa	**21**	**104**	**125**	**214**
	638	**485**	**1,123**	**1,621**
Natural Gas (bcf)				
North America	**2,743**	**459**	**3,202**	**4,100**
North Sea	**12**	**15**	**27**	**57**
Offshore West Africa	**6**	**75**	**81**	**102**
	2,761	**549**	**3,310**	**4,259**
Total Reserves (mmboe)	**1,098**	**576**	**1,674**	**2,330**

December 31, 2003	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude Oil & NGLs (mmbbl)				
North America	401	271	672	977
North Sea	138	84	222	317
Offshore West Africa	29	77	106	187
	568	432	1,000	1,481
Natural Gas (bcf)				
North America	2,665	341	3,006	3,611
North Sea	46	16	62	101
Offshore West Africa	14	72	86	111
	2,725	429	3,154	3,823
Total Reserves (mmboe)	1,022	504	1,526	2,118

CONVENTIONAL FINDING AND ONSTREAM COSTS

	2004	2003	2002	Three Year Total
Net Reserve Replacement Expenditures ($ millions)	**4,259**	2,283	3,928	10,470
Reserve Additions[8] (mmboe, net of royalties)				
Proved	**354**	185	317	856
Proved and probable	**453**	441	356	1,250
Finding and On Stream Costs Per BOE[9] (net of royalties)				
Proved	**12.03**	12.34	12.39	12.23
Proved and probable	**9.40**	5.18	11.03	8.38

(1) Reserve estimates and present value calculations are based upon year end constant reference price assumptions as detailed below.

Crude Oil & NGLs	*Company Average Price (C$/bbl)*	*WTI @ Cushing Oklahoma (US$/bbl)*	*Hardisty Heavy 12˚ API (C$/bbl)*	*North Sea Brent (US$/bbl)*
2004	*32.14*	*44.04*[10]	*17.45*	*40.47*
2003	*32.02*	*32.56*	*26.16*	*30.14*
2002	*39.23*	*31.23*	*35.04*	*30.21*

Natural Gas	*Company Average Price (C$/mcf)*	*Henry Hub Louisiana (US$/mmbtu)*	*Alberta AECO C (C$/mmbtu)*	*British Columbia Huntingdon Sumas (C$/mmbtu)*
2004	*6.44*	*6.62*[11]	*6.78*	*6.94*
2003	*6.63*	*5.80*	*6.88*	*6.94*
2002	*5.88*	*4.59*	*5.97*	*6.53*

A foreign exchange rate of US$0.84/C$1.00 was used in the 2004 evaluation. A foreign exchange rate of US$0.77/C$1.00 was used in the 2003 evaluation. A foreign exchange rate of US$0.63/C$1.00 was used in the 2002 evaluation.

(2) 2004 and 2003 proved reserve estimates and values were evaluated in accordance with the Securities and Exchange Commission (SEC) requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

(3) 2004 and 2003 proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook ("COGEH") and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

(4) Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

(5) Cost to develop represents total future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(6) Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Only future development costs and abandonment costs have been applied against future net revenues.

(7) 2002 reserve estimates were evaluated in accordance with the standards of National Policy 2-B which as now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices held constant throughout the productive life of the properties.

(8) Reserves additions are comprised of all categories of reserves changes, exclusive of production.

(9) Reserves finding and on stream costs are determined by dividing total capital costs for each year excluding cost associated with head office, abandonments, midstream and Horizon Project by reserves additions for that year.

(10) There was no trading of WTI on December 31, 2004. This posted value was determined on the basis of December 30, 2004 posted price for WTI adjusted for the change in the Brent price as posted by Platts Oilgram Price Report.

(11) There was no trading of Henry Hub on December 31, 2004. This posted value was determined on the basis of December 30, 2004 posted price for Henry Hub adjusted for the change in the AECO price as posted by the Canadian Gas Price Reporter.

FINANCIAL REVIEW

Over the past several years, Canadian Natural has been preparing its financial position to not only profitably grow its conventional crude oil and natural gas operations over the next several years, but also to build the financial capacity to start and complete the Horizon Project. A brief summary of its strengths are:

- A diverse asset base geographically (Western Canada, UK sector of North Sea, and offshore West Africa) and by product – Canadian Natural currently produces in excess of 525,000 barrels of oil equivalent per day which is approximately 44% natural gas and 56% crude oil.

- Financial stability and liquidity – a $1.5 billion bank credit facility for the Horizon Project with a 5 year term plus 3 one year renewal options. Also in December, 2004, the Company issued US$700 million of 10 year and 30 year debt securities. There were $2.8 billion of unused bank lines available at December 31, 2004.

- Strong balance sheet – with a debt to book capitalization ratio of 34%, a debt to cash flow of 1.0x, a debt to EBITDA of 0.9x and shareholders' equity of $7.3 billion.

- External hedging program – in January 2005, the Company's Board of Directors extended the hedging program to allow for 75% of forecasted crude oil and natural gas production to be hedged for 12 months forward, 50% for months 13-24 and 25% for months 25-48. As at the date hereof the Company has effectively hedged approximately 71% of 2005 and 45% of 2006 crude oil production and 67% of 2005 and 35% of 2006 natural gas production using benchmark WTI oil and AECO natural gas pricing.

- Financial flexibility – Canadian Natural's 5 and 10 year plans allow it to be proactive in its planning to allow for maximum flexibility as the Company moves forward to develop its conventional crude oil and natural gas asset base and the Horizon Oil Sands Project's mining assets.

During 2004, the Company purchased 873,400 of its common shares for a total of $33.2 million (average cost $38.01/share). The Normal Course Issuer Bid has been extended to January 2006, allowing for the repurchase of up to 13.4 million shares through facilities of the Toronto Stock Exchange and the New York Stock Exchange.

Canadian Natural's Board of Directors has approved an increase in the annual dividend paid by the Company to $0.45 per common share from the previous level of $0.40 per common share. The 12.5% increase recognizes the stability of Canadian Natural's cash flow and provides a further return to shareholders. This is the fifth consecutive year in which the Company has paid dividends and the fourth consecutive year of increase in the distribution paid to its shareholders. The increased dividend will become effective with the quarterly payment of $0.1125 per common share to be paid on April 1, 2005.

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 year and three months ended December 31, 2004 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2003.

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

Production volumes are the Company’s interest before royalties, and realized prices exclude the effect of risk management activities, except where noted otherwise.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2004	Sep 30 2004	Dec 31 2003 (1)	Year Ended Dec 31 2004	Dec 31 2003(1)
Revenue	**$ 1,969**	$ 2,075	$ 1,359	**$ 7,547**	$ 6,155
Net earnings	**$ 577**	$ 311	$ 250	**$ 1,405**	$ 1,403
Per common share – basic(2)	**$ 2.15**	$ 1.16	$ 0.93	**$ 5.24**	$ 5.23
– diluted(2)	**$ 2.13**	$ 1.13	$ 0.91	**$ 5.20**	$ 5.06
Cash flow from operations(4)	**$ 950**	$ 1,041	$ 734	**$ 3,769**	$ 3,160
Per common share – basic(2)	**$ 3.54**	$ 3.88	$ 2.74	**$ 14.06**	$ 11.77
– diluted(2)	**$ 3.52**	$ 3.85	$ 2.71	**$ 13.98**	$ 11.53
Capital expenditures, net of dispositions (3)	**$ 1,421**	$ 875	$ 662	**$ 4,633**	$ 2,506

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

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

(3) 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 area 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.

(4) Cash flow from operations is a non-GAAP term that represents net earnings 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 Dec 31 2004	Sep 30 2004	Dec 31 2003	Year Ended Dec 31 2004	Dec 31 2003
Net earnings	***$ 577***	*$ 311*	*$ 250*	***$ 1,405***	*$ 1,403*
Non-cash items:					
Stock-based compensation expense	***24***	*119*	*63*	***249***	*200*
Depletion, depreciation and amortization	***501***	*453*	*391*	***1,769***	*1,509*
Asset retirement obligation accretion	***16***	*14*	*16*	***51***	*62*
Unrealized risk management activities	***(317)***	*105*	*-*	***(40)***	*-*
Unrealized foreign exchange gain	***(77)***	*(100)*	*(86)*	***(94)***	*(343)*
Deferred petroleum revenue tax (recovery)	***(32)***	*(14)*	*(17)*	***(45)***	*(9)*
Future income tax expense	***258***	*153*	*117*	***474***	*338*
Cash flow from operations	***$ 950***	*$ 1,041*	*$ 734*	***$ 3,769***	*$ 3,160*

The Company recorded record levels of production, cash flow and net earnings for the year ended December 31, 2004 as a result of strong operational performance combined with strong commodity prices. The strong operating results are attributable to the Company following its defined growth strategy and to the strong asset base the Company has developed over time through organic growth and accretive acquisitions. The Company achieved record levels of production in 2004, reporting 513,835 boe/d before royalties for the year ended December 31, 2004 and 530,745 boe/d before royalties for the three months ended December 31, 2004. Production of crude oil and NGLs increased 17% to 282,489 bbl/d before royalties and natural gas production increased 7% to 1,388 mmcf/d before royalties for the year ended December 31, 2004. Cash flow for the year and three months ended December 31, 2004 increased 19% to $3,769 million and 29% to $950 million respectively from the comparable periods in 2003. The increase in cash flow was a result of increased production volumes and higher product prices. Net earnings reached a record $1,405 million for the year ended December 31, 2004, up from $1,403 million in 2003. Net earnings increased 131% to $577 million for the three months ended December 31, 2004 from the comparable period in the prior year. The increase is due to higher production volumes, higher commodities prices and an unrealized gain related to the mark-to-market of the Company's undesignated financial instruments.

OPERATING HIGHLIGHTS

	Three Months Ended			Year Ended	
	Dec 31 2004	**Sep 30 2004**	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Crude oil and NGLs ($/bbl, except daily production)					
Daily production (bbl/d)	**295,704**	297,262	244,262	**282,489**	242,392
Sales price(1)	**$ 36.92**	$ 43.50	$ 29.47	**$ 37.99**	$ 32.66
Royalties	**2.95**	3.59	2.22	**3.16**	2.77
Production expense	**10.41**	10.21	9.45	**10.05**	10.28
Netback	**$ 23.56**	$ 29.70	$ 17.80	**$ 24.78**	$ 19.61
Natural gas ($/mcf, except daily production)					
Daily production (mmcf/d)	**1,410**	1,396	1,270	**1,388**	1,299
Sales price(1)	**$ 6.77**	$ 6.24	$ 5.26	**$ 6.50**	$ 6.21
Royalties	**1.34**	1.39	1.05	**1.35**	1.32
Production expense	**0.68**	0.71	0.63	**0.67**	0.60
Netback	**$ 4.75**	$ 4.14	$ 3.58	**$ 4.48**	$ 4.29
Barrels of oil equivalent ($/boe, except daily production)					
Daily production (boe/d)	**530,745**	529,946	455,935	**513,835**	458,814
Sales price(1)	**$ 38.51**	$ 40.92	$ 30.43	**$ 38.45**	$ 34.84
Royalties	**5.21**	5.68	4.12	**5.37**	5.20
Production expense	**7.61**	7.59	6.81	**7.35**	7.15
Netback	**$ 25.69**	$ 27.65	$ 19.50	**$ 25.73**	$ 22.49

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

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
WTI benchmark price (US$/bbl)	**$ 48.27**	$ 43.85	$ 31.18	**$ 41.43**	$ 31.02
Dated Brent benchmark price (US$/bbl)	**$ 44.06**	$ 41.58	$ 29.42	**$ 38.28**	$ 28.83
Differential to LLB blend (US$/bbl)	**$ 19.61**	$ 12.55	$ 10.39	**$ 13.44**	$ 8.55
Condensate benchmark price (US$/bbl)	**$ 48.56**	$ 42.66	$ 31.57	**$ 41.62**	$ 31.42
NYMEX benchmark price (US$/mmbtu)	**$ 6.86**	$ 5.85	$ 4.58	**$ 6.09**	$ 5.44
AECO benchmark price (C$/GJ)	**$ 6.71**	$ 6.32	$ 5.30	**$ 6.43**	$ 6.35
US / Canadian dollar average exchange rate (US$)	**0.8195**	0.7650	0.7599	**0.7683**	0.7135

World crude oil prices remained 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. World crude oil prices have been further impacted by weather related issues causing production disruptions in the United States Gulf Coast. West Texas Intermediate ("WTI") averaged US$41.43 per bbl for the year ended December 31, 2004, up 34% compared to US$31.02 per bbl in the comparable period in 2003. WTI averaged US$48.27 per bbl in the fourth quarter of 2004, up 55% from US$31.18 per bbl in the comparable period in 2003, and up 10% from US$43.85 per bbl in the prior quarter. The impact of the higher WTI prices on the Company's heavier crude oil production was mitigated as a result of wider heavy crude oil differentials, which increased 57% to US$13.44 per bbl and 89% to US$19.61 per bbl for the year and three months ended December 31, 2004 from the comparable periods in 2003. The heavy crude oil differentials increased 56% from US$12.55 per bbl in the prior quarter of 2004. This reflects normal seasonality of lower demand for heavy crude oil during winter months as well as greater supplies of heavy crude oil on the world markets as a result of issues at refineries and upgraders. An increase in the price of diluents, required to reduce the viscosity of heavy crude oil to meet requirements for transmission in sales pipelines, contributed to lower heavy crude oil price realizations. 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. NYMEX natural gas prices increased 12% to average US$6.09 per mmbtu for the year ended December 31, 2004 from US$5.44 per mmbtu in the comparable period in 2003. AECO natural gas prices increased 1% to average $6.43 per GJ for the year ended December 31, 2004 from $6.35 per GJ in the comparable period in 2003. NYMEX natural gas prices increased 50% to average US$6.86 per mmbtu in the fourth quarter of 2004 from US$4.58 per mmbtu in the comparable period in 2003 and increased 17% from US$5.85 per mmbtu in the prior quarter. AECO natural gas prices increased 27% to average $6.71 per GJ in the fourth quarter of 2004 from $5.30 per GJ in the comparable period in 2003, and increased 6% compared to $6.32 per GJ in the prior quarter. The increase in North American natural gas prices from the third quarter is due to increased demand entering the winter heating season despite strong storage levels.

PRODUCT PRICES

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Crude oil and NGLs ($/bbl)(1)					
North America	**$ 30.99**	$ 38.31	$ 25.17	**$ 33.16**	$ 29.40
North Sea	**$ 52.77**	$ 57.39	$ 41.70	**$ 51.37**	$ 42.00
Offshore West Africa	**$ 51.28**	$ 53.86	$ 36.42	**$ 49.05**	$ 36.47
Company average	**$ 36.92**	$ 43.50	$ 29.47	**$ 37.99**	$ 32.66
Natural gas ($/mcf)(1)					
North America	**$ 6.88**	$ 6.36	$ 5.35	**$ 6.61**	$ 6.34
North Sea	**$ 3.26**	$ 3.17	$ 3.32	**$ 3.73**	$ 3.03
Offshore West Africa	**$ 4.73**	$ 6.31	$ 3.95	**$ 5.25**	$ 4.37
Company average	**$ 6.77**	$ 6.24	$ 5.26	**$ 6.50**	$ 6.21
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**53%**	60%	52%	**54%**	50%
Natural gas	**47%**	40%	48%	**46%**	50%

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

Realized crude oil prices increased 16% to average $37.99 per bbl for the year ended December 31, 2004, up from $32.66 per bbl in the comparable period in 2003, and increased 25% to average $36.92 per bbl in the fourth quarter of 2004, up from $29.47 per bbl in the comparable period in 2003. The increase in realized crude oil prices is a result of higher benchmark crude oil prices. The realized crude oil price for the three months ended December 31, 2004 decreased 15% from the previous quarter price of $43.50 per bbl as a result of the impact of higher heavy oil differentials on the Company's North America production.

The Company's realized natural gas price increased 5% to average $6.50 per mcf for the year ended December 31, 2004, up from $6.21 per mcf in the comparable period in 2003. The realized natural gas price increased 29% to $6.77 per mcf in the fourth quarter of 2004, up from $5.26 per mcf in the comparable period in 2003, and up 8% from $6.24 per mcf in the prior quarter due to changes in supply and demand fundamentals.

North America

North American realized crude oil prices increased 13% to average $33.16 per bbl for the year ended December 31, 2004, up from $29.40 per bbl in the comparable period in 2003 and increased 23% to average $30.99 per bbl in the fourth quarter of 2004, up from $25.17 per bbl in the comparable period in 2003. 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. Realized crude oil prices for the three months ended December 31, 2004 decreased 19% from the previous quarter price of $38.31 per bbl due to the impact of wider heavy crude oil differentials and the impact of a 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. As part of an industry initiative to develop new blends of Western Canadian crude oils, the Company has developed a blending capacity of up to 140 mbbl/d. The Company is contributing 123 mbbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream, a new blend of up to 10 different crude oil streams. WCS resembles a Bow River type crude with distillation cuts approximating a natural heavy oil with premium quality asphalt characteristics. The new blend has an API of 19-22 degrees and is expected to grow, with the potential to become a new benchmark for North American markets in addition to WTI. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian west coast where crude cargos can be sold on a world-wide basis.

North American realized natural gas prices increased 4% to average $6.61 per mcf for the year ended December 31, 2004, up from $6.34 per mcf in the comparable period in 2003. The realized natural gas price increased 29% to $6.88 per mcf in the fourth quarter of 2004, up from $5.35 per mcf in the comparable period in 2003, and increased 8% from $6.36 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 22% to average $51.37 per bbl for the year ended December 31, 2004, up from $42.00 per bbl in the comparable period in 2003 and increased 27% to average $52.77 per bbl in the fourth quarter of 2004, up from $41.70 per bbl in the comparable period in 2003. The increase in the realized crude oil price is due mainly to higher world crude oil prices and fluctuations in the Brent differential. Realized crude oil prices decreased 8% from the previous quarter price of $57.39 per bbl.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 34% to average $49.05 per bbl for the year ended December 31, 2004, up from $36.47 per bbl in the comparable period in 2003 and increased 41% to average $51.28 per bbl in the fourth quarter of 2004, up from $36.42 per bbl in the comparable period in 2003. The increase in the realized crude oil price is due mainly to higher world crude oil prices. The realized crude oil price decreased 5% from the previous quarter price of $53.86 per bbl.

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

	Q4 2004	Q3 2004	Q4 2003
Canadian Natural's Wellhead Price(1)			
Light crude oil and NGLs (C$/bbl)	**$ 49.34**	$ 48.77	$ 34.07
Pelican Lake crude oil (C$/bbl)	**$ 29.90**	$ 36.39	$ 24.06
Primary heavy crude oil (C$/bbl)	**$ 24.96**	$ 35.40	$ 21.50
Thermal heavy crude oil (C$/bbl)	**$ 25.52**	$ 35.19	$ 21.37
Natural gas (C$/mcf)	**$ 6.88**	$ 6.36	$ 5.35

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

DAILY PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Crude oil and NGLs (bbl/d)					
North America	**214,493**	214,336	176,429	**206,225**	174,895
North Sea	**69,971**	71,517	54,529	**64,706**	56,869
Offshore West Africa	**11,240**	11,409	13,304	**11,558**	10,628
Total	**295,704**	297,262	244,262	**282,489**	242,392
Natural gas (mmcf/d)					
North America	**1,365**	1,336	1,206	**1,330**	1,245
North Sea	**40**	53	52	**50**	46
Offshore West Africa	**5**	7	12	**8**	8
Total	**1,410**	1,396	1,270	**1,388**	1,299
Total barrel of oil equivalent (boe/d)	**530,745**	529,946	455,935	**513,835**	458,814
Product mix					
Light crude oil and NGLs	**24%**	24%	25%	**24%**	25%
Pelican Lake crude oil	**4%**	4%	5%	**4%**	5%
Primary heavy crude oil	**18%**	18%	16%	**19%**	15%
Thermal heavy crude oil	**10%**	10%	8%	**8%**	8%
Natural gas	**44%**	44%	46%	**45%**	47%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Crude oil and NGLs (bbl/d)					
North America	**187,106**	187,098	155,063	**180,011**	152,444
North Sea	**69,863**	71,396	54,728	**64,598**	56,928
Offshore West Africa	**10,908**	11,108	12,926	**11,221**	10,314
Total	**267,877**	269,602	222,717	**255,830**	219,686
Natural gas (mmcf/d)					
North America	**1,092**	1,031	957	**1,048**	976
North Sea	**40**	53	52	**50**	46
Offshore West Africa	**5**	7	11	**7**	8
Total	**1,137**	1,091	1,020	**1,105**	1,030
Total barrel of oil equivalent (boe/d)	**457,356**	451,462	392,809	**440,022**	391,361

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’s business approach is to maintain large projects 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.

The Company achieved record levels of production on a barrel of oil equivalent basis for the year ended December 31, 2004. Production before royalties on a barrel of crude oil equivalent was 513,835 bbl/d for the year ended December 31, 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 year and three months ended December 31, 2004 increased 17% or 40,097 bbl/d and 21% or 51,442 bbl/d respectively from the comparable periods in 2003. Crude oil and NGLs production before royalties for the fourth quarter decreased 1% or 1,558 bbl/d from the prior quarter and was in line with the Company’s guidance of 294,000 to 314,000 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 year and three months ended December 31, 2004 increased 7% or 89 mmcf/d and 11% or 140 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 fourth quarter of 2004 increased 1% or 14 mmcf/d from the prior quarter and was in line with the Company’s guidance of 1,385 to 1,420 mmcf/d.

The Company expects annual production levels before royalties in 2005 to average 1,448 to 1,510 mmcf/d of natural gas and 307 to 335 mbbl/d of crude oil and NGLs. First quarter 2005 production guidance before royalties is 1,400 to 1,482 mmcf/d of natural gas and 269 to 290 mbbl/d of crude oil and NGLs.

North America

Crude oil and NGLs production before royalties in North America for the year and three months ended December 31, 2004 increased 18% or 31,330 bbl/d and 22% or 38,064 bbl/d respectively from the comparable periods in 2003 due to the development of the Primrose thermal crude oil project and accretive acquisitions. Crude oil and NGLs production before royalties in the fourth quarter of 2004 remained relatively constant compared to the prior quarter.

North America natural gas production before royalties for the year and three months ended December 31, 2004 increased 7% or 85 mmcf/d and 13% or 159 mmcf/d respectively from the comparable periods in 2003. North American production of natural gas increased as a result of organic growth and accretive property acquisitions. North American natural gas production before royalties for the three months ended December 31, 2004 increased 2% or 29 mmcf/d from the prior quarter. Production of natural gas was impacted by the shut-in of 11 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 year and three months ended December 31, 2004 increased 14% or 7,837 bbl/d and 28% or 15,442 bbl/d respectively from the comparable periods in 2003. 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. Crude oil production before royalties in the fourth quarter decreased 2% or 1,546 bbl/d from the previous quarter primarily due to an unplanned extended shutdown on the Ninian North Platform. The shutdown was required to repair a power turbine used to drive water injection resulting in a loss of pressure to the reservoir. Remedial work was recently completed and production is recovering.

Natural gas production before royalties in the North Sea for the year ended December 31, 2004 increased 9% or 4 mmcf/d from the comparable period in 2003. The increase in production was due to the acquisition of properties in the Central North Sea in the third quarter of 2004 and the increased working interests acquired in the Banff Field during 2003. The increase was partially offset by the commencement of the natural gas reinjection program in the Banff Field in the fourth quarter of 2004. Despite some delays and production interruptions during commissioning, results to date are positive with full production benefit expected to commence during the second quarter of 2005. Natural gas production for the fourth quarter decreased 23% or 12 mmcf/d from the comparable period in 2003 and decreased 25% or 13 mmcf/d from the prior quarter due to the commencement of the natural gas reinjection program in the Banff Field.

Offshore West Africa

Offshore West Africa crude oil production before royalties for the year ended December 31, 2004 increased 9% or 930 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 during 2003. Crude oil production before royalties for the three months ended December 31, 2004 decreased 16% or 2,064 bbl/d from the comparable period in 2003, and decreased 1% or 169 bbl/d from the prior quarter.

Natural gas production before royalties in Offshore West Africa remained constant at 8 mmcf/d for the year ended December 31, 2004. Natural gas production decreased 58% or 7 mmcf/d for the three months ended December 31, 2004 from the comparable periods in 2003 and decreased 29% or 2 mmcf/d from the prior quarter.

ROYALTIES

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Crude oil and NGLs ($/bbl)					
North America	**$ 3.96**	$ 4.87	$ 3.05	**$ 4.21**	$ 3.79
North Sea	**$ 0.08**	$ 0.09	$ (0.15)	**$ 0.08**	$ (0.03)
Offshore West Africa	**$ 1.52**	$ 1.42	$ 1.03	**$ 1.43**	$ 1.08
Company average	**$ 2.95**	$ 3.59	$ 2.22	**$ 3.16**	$ 2.77
Natural gas ($/mcf)					
North America	**$ 1.39**	$ 1.45	$ 1.10	**$ 1.40**	$ 1.38
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.14**	$ 0.17	$ 0.11	**$ 0.15**	$ 0.13
Company average	**$ 1.34**	$ 1.39	$ 1.05	**$ 1.35**	$ 1.32
Company average ($/boe)	**$ 5.21**	$ 5.68	$ 4.12	**$ 5.37**	$ 5.20
Percentage of revenue[(1)]					
Crude oil and NGLs	**8%**	8%	8%	**8%**	9%
Natural gas	**20%**	22%	20%	**21%**	21%
Boe	**14%**	14%	14%	**14%**	15%

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

North America

North America crude oil and NGLs royalties increased from both the comparable periods in 2003 due to higher benchmark crude oil prices. North America crude oil and NGLs royalties decreased from the prior quarter due to the Company's lower realized crude oil price as a result of the wider heavy oil differential and a stronger Canadian dollar.

Natural gas royalties as a percentage of revenue fluctuated from 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			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Crude oil and NGLs ($/bbl)					
North America	**$ 9.06**	$ 9.10	$ 8.43	**$ 8.94**	$ 9.14
North Sea	**$ 14.96**	$ 13.88	$ 13.42	**$ 14.03**	$ 14.07
Offshore West Africa	**$ 7.82**	$ 8.05	$ 6.67	**$ 7.59**	$ 8.68
Company average	**$ 10.41**	$ 10.21	$ 9.45	**$ 10.05**	$ 10.28
Natural gas ($/mcf)					
North America	**$ 0.63**	$ 0.63	$ 0.60	**$ 0.62**	$ 0.57
North Sea	**$ 2.29**	$ 2.48	$ 1.16	**$ 2.07**	$ 1.33
Offshore West Africa	**$ 1.31**	$ 1.39	$ 1.18	**$ 1.33**	$ 1.39
Company average	**$ 0.68**	$ 0.71	$ 0.63	**$ 0.67**	$ 0.60
Company average ($/boe)	**$ 7.61**	$ 7.59	$ 6.81	**$ 7.35**	$ 7.15

North America

North American crude oil and NGLs production expense for the year ended December 31, 2004 decreased from the comparable period in 2003. The decrease was primarily 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 crude oil and NGLs production expense for the three months ended December 31, 2004 increased from the comparable period in 2003 due to the impact of higher natural gas prices on the costs of fuel used. In 2004, the increased activity in the oil and gas sector in reaction to higher commodity prices resulted in higher production expense, especially as the labour market tightened. In addition, the cost of steel products increased in 2004 due to increased global demand.

North American natural gas production expense per mcf for the year and three months ended December 31, 2004 increased from the comparable periods in 2003. The increase is partly due to the cost pressures noted above and partly due to increased production in certain areas such as Northeast British Columbia where the Company is incurring higher costs associated with third party processing and gathering.

North Sea

North Sea crude oil production expense varied 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			Year Ended	
($ millions)	**Dec 31 2004**	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Revenue	**$ 18**	$ 17	$ 16	**$ 68**	$ 61
Production expense	**5**	6	4	**20**	15
Midstream cash flow	**13**	11	12	**48**	46
Depreciation	**2**	2	1	**7**	7
Segment earnings before taxes	**$ 11**	$ 9	$ 11	**$ 41**	$ 39

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 year and three months ended December 31, 2004 increased from the comparable periods in 2003 due to the expansion of the ECHO Pipeline.

DEPLETION, DEPRECIATION AND AMORTIZATION(2)

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003(1)	**Dec 31 2004**	Dec 31 2003(1)
Expense ($ millions)	**$ 499**	$ 451	$ 390	**$ 1,762**	$ 1,502
$/boe	**$ 10.24**	$ 9.27	$ 9.26	**$ 9.37**	$ 8.96

(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 year and three months ended December 31, 2004 increased in total and per boe from the comparable periods in the prior year. The increase in 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, future abandonment costs associated with the acquisition of additional properties in the North Sea, and higher costs to develop the Company's proved undeveloped reserves.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003(1)	**Dec 31 2004**	Dec 31 2003(1)
Expense ($ millions)	**$ 16**	$ 14	$ 16	**$ 51**	$ 62
$/boe	**$ 0.33**	$ 0.29	$ 0.38	**$ 0.27**	$ 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			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Net expense ($ millions)	**$ 34**	$ 31	$ 24	**$ 115**	$ 87
$/boe	**$ 0.69**	$ 0.62	$ 0.58	**$ 0.61**	$ 0.52

Administration expense for the year and three months ended December 31, 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			Year Ended	
	Dec 31 2004	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Stock option plan ($ millions)	**$ 24**	$ 119	$ 63	**$ 249**	$ 200
Share bonus plan ($ millions)	**2**	1	-	**10**	-
Total ($ millions)	**$ 26**	$ 120	$ 63	**$ 259**	$ 200
$/boe	**$ 0.53**	$ 2.45	$ 1.50	**$ 1.37**	$ 1.20

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 December 31, 2004 of $323 million (September 30, 2004 - $315 million; December 31, 2003 - $171 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 year ended December 31, 2004 is $249 million ($168 million after tax).

For the year ended December 31, 2004, the Company paid $80 million for stock options surrendered for cash settlement (nine months ended September 30, 2004 - $66 million; year ended December 31, 2003 - $31 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 year ended December 31, 2004, the Company has recognized $10 million ($6 million after tax) of compensation expense under the Share Bonus Plan.

INTEREST EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2004	Sep 30 2004 (1)	Dec 31 2003 (1) (2)	**Dec 31 2004**	Dec 31 2003 (1) (2)
Interest expense, net ($ millions)	**$ 48**	$ 47	$ 43	**$ 189**	$ 201
$/boe	**$ 1.00**	$ 0.98	$ 1.03	**$ 1.01**	$ 1.20
Average effective interest rate	**5.1%**	5.2%	5.7%	**5.2%**	5.8%

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

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

Interest expense 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, $32 million of realized gains on certain of its fixed to floating interest rate swaps are included in risk management activities for the year ended December 31, 2004. Interest expense decreased on a total and boe basis for the year ended December 31, 2004 from the comparable period in 2003 mainly due to lower borrowing rates. Interest expense increased slightly on a total basis for the three months ended December 31, 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 or speculative 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 principal 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 other 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 year and three months ended December 31, 2004:

RISK MANAGEMENT

($ millions)	Three Months Ended **Dec 31 2004**	Sep 30 2004	Dec 31 2003	Year Ended **Dec 31 2004**	Dec 31 2003
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 180**	$ 176	$ (12)	**$ 501**	$ 95
Natural gas financial instruments	**2**	1	3	**5**	88
Interest rate swaps	**(7)**	(6)	(8)	**(32)**	(35)
Total	**$ 175**	$ 171	$ (17)	**$ 474**	$ 148
Unrealized (gain) loss					
Crude oil and NGLs financial instruments	**$ (321)**	$ 107	$ -	**$ (47)**	$ -
Natural gas financial instruments	**-**	-	-	**-**	-
Interest rate swaps	**4**	(2)	-	**7**	-
Total	**$ (317)**	$ 105	$ -	**$ (40)**	$ -
Total	**$ (142)**	$ 276	$ (17)	**$ 434**	$ 148

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

	Three Months Ended **Dec 31 2004**	Sep 30 2004	Dec 31 2003	Year Ended **Dec 31 2004**	Dec 31 2003
Crude oil and NGLs ($/bbl)	**$ 6.63**	$ 6.45	$ (0.55)	**$ 4.85**	$ 1.07
Natural gas ($/mcf)	**$ -**	$ 0.01	$ 0.03	**$ 0.01**	$ 0.19

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

($ millions, except interest rates)	Three Months Ended **Dec 31 2004**	Sep 30 2004(1)	Dec 31 2003(1)	Year Ended **Dec 31 2004**	Dec 31 2003(1)
Interest expense as per the financial statements	**$ 48**	$ 47	$ 43	**$ 189**	$ 201
Less: realized risk management gain	**(7)**	(6)	(8)	**(32)**	(35)
	$ 41	$ 41	$ 35	**$ 157**	$ 166
Average effective interest rate	**4.6%**	4.5%	4.6%	**4.4%**	4.8%

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

FOREIGN EXCHANGE

($ millions)	Three Months Ended Dec 31 2004	Three Months Ended Sep 30 2004	Three Months Ended Dec 31 2003	Year Ended Dec 31 2004	Year Ended Dec 31 2003
Realized foreign exchange loss (gain)	**$ 16**	$ 1	$ (6)	**$ 3**	$ 8
Unrealized foreign exchange gain[(1)]	**(77)**	(100)	(86)	**(94)**	(343)
	$ (61)	$ (99)	$ (92)	**$ (91)**	$ (335)

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

The majority of the unrealized foreign exchange gain is related to the fluctuation in the Canadian dollar in relation to the US dollar. The Canadian dollar ended the year 2004 at US$0.8308 compared to US$0.7738 at December 31, 2003 (September 30, 2004 – US$0.7912).

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 Dec 31 2004	Three Months Ended Sep 30 2004	Three Months Ended Dec 31 2003	Year Ended Dec 31 2004	Year Ended Dec 31 2003
Taxes other than income tax					
Current	**$ 47**	$ 76	$ 43	**$ 210**	$ 116
Deferred	**(32)**	(14)	(17)	**(45)**	(9)
Total	**$ 15**	$ 62	$ 26	**$ 165**	$ 107
Current income tax					
North America – Current income tax	**$ 1**	$ 6	$ 3	**$ 89**	$ 43
North America – Large corporations tax	**5**	2	1	**11**	16
North Sea	**(16)**	(19)	2	**2**	23
Offshore West Africa	**3**	3	3	**13**	10
Other	**1**	-	-	**1**	-
Total	**$ (6)**	$ (8)	$ 9	**$ 116**	$ 92
Future income tax expense	**$ 258**	$ 153	$ 117	**$ 474**	$ 338
Effective income tax rate[(1)]	**30.4%**	31.8%	33.5%	**29.6%**	23.5%

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

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 year ended December 31, 2004 decreased to $11 million from $16 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 North Sea recorded a recovery of current income tax expense in the third and fourth quarter of 2004 due to the tax pools acquired in a recent acquisition being immediately deductible.

For the year ended December 31, 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 $278 million in 2003.

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

	Three Months Ended			Year Ended	
($ millions, except income tax rates)	**Dec 31 2004**	Sep 30 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Income tax as reported					
Current income tax (recovery)	**$ (6)**	$ (8)	$ 9	**$ 116**	$ 92
Future income tax expense[1]	**258**	153	117	**474**	338
	252	145	126	**590**	430
Alberta corporate tax rate reduction	**-**	-	**-**	**66**	31
Federal corporate tax rate reduction	**-**	-	31	**-**	247
Total	**$ 252**	$ 145	$ 157	**$ 656**	$ 708
Expected effective income tax rate	**30.4%**	31.8%	34.1%	**32.9%**	43.5%

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

CAPITAL EXPENDITURES

($ millions)	Three Months Ended Dec 31 2004	Sep 30 2004	Dec 31 2003	Year Ended Dec 31 2004	Dec 31 2003
Expenditures on property, plant and equipment					
Net property acquisitions (1)	**$ 761**	$ 290	$ 29	**$ 1,835**	$ 336
Land acquisition and retention	**13**	**37**	44	**120**	154
Seismic evaluations	**21**	**25**	25	**89**	77
Well drilling, completion and equipping	**359**	**221**	352	**1,394**	1,194
Pipeline and production facilities	**185**	**190**	133	**821**	522
Total net reserve replacement expenditures	**1,339**	**763**	583	**4,259**	2,283
Horizon Oil Sands Project	**58**	**84**	52	**291**	152
Midstream	**11**	**2**	2	**16**	11
Abandonments	**5**	**14**	20	**32**	40
Head office	**8**	**12**	5	**35**	20
Total net capital expenditures	**$ 1,421**	$ **875**	$ 662	**$ 4,633**	$ 2,506
By segment					
North America	**$ 1,141**	$ **339**	$ 431	**$ 3,355**	$ 1,769
North Sea	**87**	**370**	106	**608**	338
Offshore West Africa	**111**	**54**	46	**296**	176
Horizon Oil Sands Project	**58**	**84**	52	**291**	152
Midstream	**11**	**2**	2	**16**	11
Abandonments	**5**	**14**	20	**32**	40
Head office	**8**	**12**	5	**35**	20
Total	**$ 1,421**	$ **875**	$ 662	**$ 4,633**	$ 2,506

(1) 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 area 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.

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.

In the year 2004, capital expenditures were $4,633 million, including the acquisition of Petrovera, compared to $2,506 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 1,449 net wells consisting of 689 natural gas wells, 328 crude oil wells, 336 stratigraphic test and service wells, and 96 wells that were dry and abandoned compared to 1,793 net wells in 2003. The total number of wells drilled decreased from the prior year due to the reallocation of capital resulting from the strategic acquisitions completed in 2004. The Company achieved an overall success rate of 91%, 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 fourth quarter of 2004 were $1,421 million compared to $662 million in the comparable period in 2003. In the fourth quarter the Company drilled 333 net wells, including 60 stratigraphic test and service wells.

North America

North America accounted for 80% of the total capital expenditures in 2004 compared to 79% in the comparable period in the prior year.

During the fourth quarter, the Company drilled 162 net wells targeting natural gas, including 56 wells in North Alberta, 54 wells in South Alberta targeting shallow gas, 42 wells in Northwest Alberta and 10 wells in Northeast British Columbia. The Company also drilled 107 net wells targeting crude oil during the fourth quarter 2004. These wells were concentrated in the Company's crude oil region of North Alberta where 90 heavy crude oil wells were drilled. Also included in this figure were 13 high-pressure horizontal thermal crude oil wells that were drilled and completed at Primrose as part of the 2004 development strategy of the area.

In addition, the Company continues exploitation of the Cardium reserves in Northwest Alberta with the drilling of 18 wells, all of which were successful.

During the fourth quarter, the Company increased capital spending levels directed toward natural gas drilling in an effort to reduce pressures of a tight 2005 winter drilling season by starting earlier. This effort included a detailed and sequential drilling program that facilitated the procurement of better drilling rigs and crews for the winter season; both of which are an integral part of cost control. Certain portions of the drilling program were delayed due to warmer than expected weather through mid-December; however, the Company still expects to complete the majority of its plan.

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 to augment 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. The polymer flood pilot will commence during 2005 with three injectors and five producers.

In the fourth quarter of 2004, the Company completed the acquisition of certain resource properties located in Alberta, British Columbia and Saskatchewan. The acquisition also includes over 510,000 net acres of unproven land. The acquisition has been included in operations effective December 2004. The acquisition fits the Company's strategy of dominating its core areas and related infrastructure, as the vast majority of the properties acquired are located within it core areas. The acquisition extends the Company's North Alberta core region into the light oil operating area of Dawson. Consistent with similar acquisitions in 2004, this acquisition is expected to provide additional free cash flow during the construction years of the Horizon Oil Sands Project.

In the Horizon Oil Sands Project ("Horizon Project"), the third phase of the front-end engineering, Engineering Design Specification ("EDS"), was completed and ongoing detail work continues. The EDS provided sufficient definition for a lump sum inquiry for the detailed Engineering, Procurement and Construction ("EPC") of the various project components. The EDS also provided a detailed cost estimate and the basis upon which management made the final recommendation to the Board of Directors for a sanction of the Horizon Project. In the fourth quarter, site preparation work continued as well as work on the construction of onsite access roads, camps and the installation of deep undergrounds. In addition, clarification of bid documents occurred, resulting in the Company being able to obtain approximately 68% of Phase 1 costs on a fixed cost basis. The current estimate for phase one construction costs now totals approximately $6.8 billion, including a contingency reserve of $700 million. The total cost for all three phases of the Horizon Project is now expected to be approximately $10.8 billion.

The Cold Lake Pipeline Limited Partnership, in which the Company has a 15% working interest, completed the construction of the DilSynBit project in October 2004.

North Sea

In the fourth quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the fourth quarter one production and one injection well were completed at the Columba B terrace, and the Playfair well was completed with a production rate of 5 mbbl/d and sufficient associated natural gas to provide the Murchison Platform energy needs, thereby reducing production costs.

The Company continued implementation of the natural gas reinjection project at the Banff Field in the Central North Sea with reinjection commencing in November 2004. The project is expected to increase the overall reservoir recovery of crude oil, but will result in reductions in natural gas volumes.

Offshore West Africa

Offshore West Africa capital expenditures include the development of the Baobab Field where 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") has been completed and is now moored on location. The installation of subsea equipment and pipelines commenced during the first quarter of 2005 and is progressing to plan for first production, expected in the second quarter of 2005.

During the fourth quarter of 2004, the Acajou North exploration well was drilled to delineate the extent of the previously drilled Acajou discovery. The result of this well, however, did not yield sufficient hydrocarbons to merit a stand alone development at Acajou. This field is being evaluated for future tie-back to East Espoir. At Zaizou, an exploration well spudded late in the fourth quarter was unsuccessful and the data obtained from this well is currently being used to trace the pattern of oil migration in the area to help identify future exploration targets.

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 with various components out for bid. The development is progressing on schedule and is expected to commence production in mid 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 continues to evaluate alternatives for its holdings in the Block.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2004**		Sep 30 2004[1]		Dec 31 2003[1]
Working capital deficit[2]	**$**	**652**	$	633	$	505
Long-term debt	**$**	**3,538**	$	3,415	$	2,748
Shareholders' equity						
Share capital		**2,408**		2,400		2,353
Retained earnings		**4,922**		4,372		3,650
Foreign currency translation adjustment		**(6)**		1		3
Total	**$**	**7,324**	$	6,773	$	6,006
Debt to cash flow[2][3]		**1.0x**		0.9x		0.9x
Debt to EBITDA[2][3]		**0.9x**		0.8x		0.8x
Debt to book capitalization[2]		**33.8%**		32.9%		32.8%
Debt to market capitalization[2]		**21.4%**		19.7%		25.1%
After tax return on average common shareholders' equity[3]		**21.4%**		17.2%		25.6%
After tax return on average capital employed[2][3]		**15.3%**		12.5%		17.1%

(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 December 31, 2004, the working capital deficit amounted to $652 million and includes the current portion of other long-term liabilities of $260 million, consisting of stock based compensation of $243 million and the mark to market valuation of certain Risk Management financial derivative instruments of $17 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 surrender. 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 December 31, 2004.

The Company is committed to maintaining its strong financial position throughout construction of the Horizon Project. In 2004, strong operational results and strong commodity prices enabled the Company to maintain debt levels at 33.8% of book capitalization. The Company has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery of exceptional low risk conventional oil and natural gas growth opportunities. 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 a strong balance sheet. Existing proved development projects, which have largely been funded prior to December 31, 2004, such as Baobab, Primrose and West Espoir provide identified growth in production volumes in 2005 and 2006, and will generate incremental free cash flows during the period 2005 to 2008 with which to finance the Horizon Project.

In January 2005, the Board of Directors of the Company authorized an expanded hedging program for the Company in an effort to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow through the Horizon Project construction period. This expanded program allows for up to 75% of the near 12 months estimated production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48 to be hedged. This revised hedging program allows the Company to have greater stability in its free cash flow and enhances the Company's financial flexibility during the Horizon Project construction years. The Company currently has collar hedges covering approximately 71% and 45% of estimated 2005 and 2006 crude oil production respectively. Similarly, approximately 67% and 35% of estimated 2005 and 2006 natural gas production has been hedged. The Company may also look to offload capital commitments through the acceptance of complementary business partners, or potentially, project joint venture partners.

Long-term debt

In November 2004, the Company issued US$350 million of US dollar debt securities maturing on December 1, 2014, bearing interest at 4.90% and US$350 million of US dollar securities maturing on February 1, 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into certain interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 1, 2014.

In December 2004, the Company executed a $1,500 million, 5-year revolving credit facility, with three, one year extension options.

At December 31, 2004, the Company had undrawn bank lines of credit of $2,842 million.

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 December 31, 2004, there were 268,181,000 common shares outstanding. As at February 18, 2005 there were 268,221,000 common shares outstanding.

In January 2005, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 13,409,006 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2005 and ending January 23, 2006.

As at December 31, 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 pursuant to a Normal Course Issuer Bid which has been in place since January 24, 2004.

In February 2005, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.45 per common share for 2005. The 12.5% increase recognizes the stability of the Company's cash flow and provides a return to Shareholders. This is the fifth consecutive year in which the Company has paid dividends and the fourth consecutive year of an increase in the distribution paid to its Shareholders. In February 2004, the Company's Board of Directors approved increased 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.

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 a liability for the fair value of the asset retirement obligation related to long-term assets. Retirement costs equal to the fair value of the asset 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 6 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 gain of $40 million ($27 million, net of tax) for the year ended December 31, 2004 relating to its financial instruments. The unrealized gain assumes that all unsettled derivative financial instruments were settled on December 31, 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 earlier in the MD&A and in notes 2 and 4 of the consolidated financial statements.

Preferred securities

Effective December 31, 2004, the Company early adopted changes to CICA Handbook section 3860 "Financial Instruments – Presentation and Disclosure" that relate to contractual obligations that may be settled by delivery of the Company's common shares. Under the new rules, these obligations must be classified as liabilities on the Company's balance sheets. Previously, these obligations were classified as equity. These changes have been adopted retroactively and prior periods have been restated. The effects on the Company's consolidated financial statements are discussed in note 2 of the consolidated financial statements.

SUBSEQUENT EVENT

On February 9, 2005, the Company's Board of Directors unanimously authorized the Company to proceed with Phase 1 of the Horizon Oil Sands Project. The Horizon Project is designed as a phased development and includes the mining of bitumen and an onsite upgrader. Phase 1 production is targeted to begin two components at 110,000 bbl/d of 34^{o} API light sweet, synthetic crude oil ("SCO"). Phase 2 would increase production to 155,000 bbl/d of SCO. Phase 3 would further increase production to 232,000 bbl/d of SCO. Total expected capital costs for all three phases of the development are estimated at $10.8 billion. Capital costs for the first phase of the Horizon Project are estimated at $6.8 billion including a contingency reserve of $700 million, with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008, respectively.

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 fourth 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	$ 96	$ 0.36	$ 68	$ 0.25
Including financial derivatives	$ 80	$ 0.30	$ 43	$ 0.16
Natural gas – AECO C$0.10/mcf(3)				
Excluding financial derivatives	$ 37	$ 0.14	$ 24	$ 0.09
Including financial derivatives	$ 33	$ 0.12	$ 21	$ 0.08
Volume changes				
Crude oil – 10,000 bbl/d	$ 73	$ 0.27	$ 34	$ 0.13
Natural gas – 10 mmcf/d	$ 18	$ 0.07	$ 7	$ 0.03
Foreign currency rate change				
$0.01 change in C$ in relation to US$(3)				
Excluding financial derivatives	$ 56	$ 0.21	$ 12	$ 0.05
Including financial derivatives	$ 55 – 58	$ 0.21 – 0.22	$ 12 – 13	$ 0.04 – 0.05
Interest rate change - 1%	$ 13	$ 0.05	$ 13	$ 0.05

(1) The sensitivities are calculated based on 2004 fourth 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 12.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe, except daily production)	Three Months Ended **Dec 31 2004**	 Sep 30 2004	 Dec 31 2003	Year Ended **Dec 31 2004**	 Dec 31 2003
Daily production (boe/d)	**530,745**	529,946	455,935	**513,835**	458,814
Sales price[1]	**$ 38.51**	$ 40.92	$ 30.43	**$ 38.45**	$ 34.84
Royalties	**5.21**	5.68	4.12	**5.37**	5.20
Production expense[2]	**7.61**	7.59	6.81	**7.35**	7.15
Netback	**25.69**	27.65	19.50	**25.73**	22.49
Midstream contribution[2]	**(0.27)**	(0.25)	(0.29)	**(0.26)**	(0.28)
Administration	**0.69**	0.62	0.58	**0.61**	0.52
Share bonus plan	**0.03**	0.03	-	**0.05**	-
Interest	**1.00**	0.99	1.03	**1.01**	1.20
Risk management activities loss (gain) – realized	**3.58**	3.51	(0.21)	**2.52**	1.09
Foreign exchange loss (gain) – realized	**0.33**	0.01	(0.17)	**0.02**	0.05
Taxes other than income tax (current)	**0.98**	1.55	1.02	**1.12**	0.69
Current income tax (North America)	**0.02**	0.12	0.07	**0.47**	0.14
Current income tax (Large corporations tax)	**0.09**	0.06	0.07	**0.05**	0.06
Current income tax (North Sea)	**(0.32)**	(0.42)	0.07	**0.01**	0.26
Current income tax (Offshore West Africa)	**0.07**	0.07	0.01	**0.07**	0.09
Current income tax (other)	**0.03**	-	-	**0.01**	-
Cash flow	**$ 19.46**	$ 21.36	$ 17.32	**$ 20.05**	$ 18.67

(1) Including transportation costs.

(2) Excluding intersegment eliminations.

SEGMENTED NETBACK	Year Ended December 31, 2004			
	North America	North Sea	Offshore West Africa	Total
Crude oil and NGLs ($/bbl, except daily production)				
Daily production (bbl/d)	**206,225**	**64,706**	**11,558**	**282,489**
Sales price[1]	**$ 33.16**	**$ 51.37**	**$ 49.05**	**$ 37.99**
Royalties	**4.21**	**0.08**	**1.43**	**3.16**
Production expense	**8.94**	**14.03**	**7.59**	**10.05**
Netback	**$ 20.01**	**$ 37.26**	**$ 40.03**	**$ 24.78**
Natural gas ($/mcf, except daily production)				
Daily production (mmcf/d)	**1,330**	**50**	**8**	**1,388**
Sales price[1]	**$ 6.61**	**$ 3.73**	**$ 5.25**	**$ 6.50**
Royalties	**1.40**	**-**	**0.15**	**1.35**
Production expense	**0.62**	**2.07**	**1.33**	**0.67**
Netback	**$ 4.59**	**$ 1.66**	**$ 3.77**	**$ 4.48**
Barrels of oil equivalent ($/boe, except daily production)				
Daily production (boe/d)	**427,936**	**73,093**	**12,806**	**513,835**
Sales price[1]	**$ 36.55**	**$ 48.02**	**$ 47.34**	**$ 38.45**
Royalties	**6.40**	**0.08**	**1.38**	**5.37**
Production expense	**6.23**	**13.84**	**7.63**	**7.35**
Netback	**$ 23.92**	**$ 34.10**	**$ 38.33**	**$ 25.73**

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	**Dec 31 2004**	Dec 31 2003[1]
ASSETS		
Current assets		
Cash	**$ 28**	$ 104
Accounts receivable and other	**1,176**	751
Current portion of other long-term assets (note 4)	**34**	-
	1,238	855
Property, plant and equipment (net)	**17,064**	13,714
Other long-term assets (note 4)	**108**	74
	$ 18,410	$ 14,643
LIABILITIES		
Current liabilities		
Accounts payable	**$ 379**	$ 464
Accrued liabilities	**1,057**	582
Current portion of long-term debt (note 5)	**194**	184
Current portion of other long-term liabilities (note 6)	**260**	130
	1,890	1,360
Long-term debt (note 5)	**3,538**	2,748
Other long-term liabilities (note 6)	**1,208**	938
Future income tax (note 7)	**4,450**	3,591
	11,086	8,637
SHAREHOLDERS' EQUITY		
Share capital (note 8)	**2,408**	2,353
Retained earnings	**4,922**	3,650
Foreign currency translation adjustment (note 9)	**(6)**	3
	7,324	6,006
	$ 18,410	$ 14,643

(1) Restated (note 2).

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Dec 31 2004**	Three Months Ended Dec 31 2003(1)	Year Ended **Dec 31 2004**	Year Ended Dec 31 2003(1)
Revenue	**$ 1,969**	$ 1,359	**$ 7,547**	$ 6,155
Less: royalties	**(255)**	(173)	**(1,011)**	(872)
Revenue, net of royalties	**1,714**	1,186	**6,536**	5,283
Expenses				
Production	**377**	288	**1,400**	1,209
Transportation	**71**	68	**250**	262
Depletion, depreciation and amortization	**501**	391	**1,769**	1,509
Asset retirement obligation accretion (note 6)	**16**	16	**51**	62
Administration	**34**	24	**115**	87
Stock-based compensation (note 6)	**26**	63	**259**	200
Interest	**48**	43	**189**	201
Risk management activities	**(142)**	(17)	**434**	148
Foreign exchange gain	**(61)**	(92)	**(91)**	(335)
	870	784	**4,376**	3,343
Earnings before taxes	**844**	402	**2,160**	1,940
Taxes other than income tax	**15**	26	**165**	107
Current income tax (recovery) expense (note 7)	**(6)**	9	**116**	92
Future income tax expense (note 7)	**258**	117	**474**	338
Net earnings	**577**	250	**1,405**	1,403
Net earnings per common share (note 10)				
Basic	**$ 2.15**	$ 0.93	**$ 5.24**	$ 5.23
Diluted	**$ 2.13**	$ 0.91	**$ 5.20**	$ 5.06

(1) Restated (note 2).

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Year Ended 2004	2003[1]
Balance – beginning of year as previously reported	**$ 3,644**	$ 2,414
Change in accounting policy (note 2)	**6**	10
Balance – beginning of year as restated	**3,650**	2,424
Net earnings	**1,405**	1,403
Dividend on common shares (note 8)	**(107)**	(81)
Purchase of common shares (note 8)	**(26)**	(96)
Balance – end of year	**$ 4,922**	$ 3,650

(1) Restated (note 2).

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2004	Three Months Ended Dec 31 2003(1)	Year Ended Dec 31 2004	Year Ended Dec 31 2003(1)
Operating activities				
Net earnings	**$ 577**	$ 250	**$ 1,405**	$ 1,403
Non-cash items				
Depletion, depreciation and amortization	**501**	391	**1,769**	1,509
Asset retirement obligation accretion	**16**	16	**51**	62
Stock-based compensation	**24**	63	**249**	200
Deferred petroleum revenue tax (recovery)	**(32)**	(17)	**(45)**	(9)
Unrealized risk management activities	**(317)**	-	**(40)**	-
Future income tax	**258**	117	**474**	338
Unrealized foreign exchange gain	**(77)**	(86)	**(94)**	(343)
Deferred charges	**(36)**	5	**(33)**	10
Abandonment expenditures	**(5)**	(20)	**(32)**	(40)
Net change in non-cash working capital	**37**	41	**(14)**	(48)
	946	760	**3,690**	3,082
Financing activities				
(Repayment) issue of bank credit facilities	**(386)**	(13)	**357**	(647)
Repayment of medium-term notes	**-**	-	**(125)**	-
Repayment of senior unsecured notes	**-**	-	**(54)**	(85)
Repayment of obligations under capital leases	**-**	(1)	**(7)**	(8)
Issue US debt securities	**830**	-	**830**	-
Issue of common shares	**2**	6	**24**	89
Purchase of common shares	**-**	(21)	**(33)**	(144)
Dividend on common shares	**(27)**	(20)	**(101)**	(77)
Net change in non-cash working capital	**4**	(9)	**6**	(11)
	423	(58)	**897**	(883)
Investing activities				
Expenditures on property, plant and equipment	**(1,420)**	(643)	**(4,582)**	(2,486)
Net proceeds on sale of property, plant and equipment	**3**	1	**7**	20
Net expenditures on property, plant and equipment	**(1,417)**	(642)	**(4,575)**	(2,466)
Net change in non-cash working capital	**64**	14	**(88)**	341
	(1,353)	(628)	**(4,663)**	(2,125)
Increase (decrease) in cash	**16**	74	**(76)**	74
Cash – beginning of period	**12**	30	**104**	30
Cash – end of period	**$ 28**	$ 104	**$ 28**	$ 104

(1) Restated (note 2).

Supplemental disclosure of cash flow information (note 11)

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 a liability for the fair value of the asset retirement obligation related to long-term assets. Retirement costs equal to the fair value of the asset 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:

	Year Ended			
		Dec 31 2004		Dec 31 2003
Increase opening retained earnings	**$**	**6**	$	10
Decrease depletion, depreciation and amortization	**$**	**(120)**	$	(56)
Increase asset retirement obligation accretion	**$**	**51**	$	62
Increase (decrease) future income tax expense	**$**	**28**	$	(2)

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 12) as hedges including certain crude oil collar, natural gas collars, the currency swap on the US$125 million senior unsecured note, and certain interest rate swaps. 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.

Preferred securities

Effective December 31, 2004, the Company early adopted changes to CICA Handbook section 3860 "Financial Instruments – Presentation and Disclosure" that relate to contractual obligations that may be settled by delivery of the Company's common shares. Under the new rules, these obligations must be classified as liabilities on the Company's balance sheets. Previously, these obligations were classified as equity. These changes have been adopted retroactively and prior periods have been restated. Adoption of the changes had the following effects on the Company's consolidated financial statements:

	Year Ended			
		Dec 31 2004		Dec 31 2003
Increase long-term debt	**$**	**96**	$	103
Decrease preferred securities	**$**	**(96)**	$	(103)
Increase interest expense	**$**	**9**	$	9
Increase foreign exchange gain	**$**	**7**	$	23
(Decrease) increase future income tax expense	**$**	**(1)**	$	1
Decrease dividend on preferred securities, net of tax	**$**	**(5)**	$	(5)
Decrease revaluation of preferred securities, net of tax	**$**	**(4)**	$	(18)

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 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

Purchase price allocated as follows:		
Property, plant and equipment	$	643
Future income tax liability		(129)
Asset retirement obligation		(43)
	$	471

4. OTHER LONG–TERM ASSETS

		Dec 31 2004		Dec 31 2003
Risk management	**$**	**66**	$	-
Deferred charges		**76**		74
		142		74
Less: current portion		**34**		-
	$	**108**	$	74

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:

	Risk management mark-to-market
Fair value of financial instruments – beginning of year	**$ 40**
Change in fair value of financial instruments	**26**
Fair value of financial instruments – end of year	**66**
Less: current portion	**34**
	32

5. LONG-TERM DEBT

	Dec 31 2004	Dec 31 2003
Bank credit facilities		
Bankers' acceptances	**$ -**	$ -
US dollar bankers' acceptances (2004 – US$471 million, 2003 – US$207 million)	**557**	268
Medium-term notes	**125**	250
Senior unsecured notes (2004 – US$218 million, 2003 – US$258 million)	**306**	366
Preferred securities (2004 – US$80 million, 2003 – US$80 million)	**96**	103
US dollar debt securities (2004 – US$2,200 million, 2003 – US$1,500 million)	**2,648**	1,938
Obligations under capital leases	**-**	7
	3,732	2,932
Less: current portion of long-term debt	**194**	184
	$ 3,538	$ 2,748

Bank credit facilities

At December 31, 2004, the Company had unsecured bank credit facilities of $3,425 million comprised of a $100 million operating demand facility, a revolving credit and term-loan facility of $1,825 million and a new $1,500 million, 5-year revolving credit facility executed in December 2004 with three, one year extension options.

Through foreign currency financial derivatives, the Company has fixed the exchange rate on the repayment of its US dollar bankers' acceptances (note 12). The US dollar bankers' acceptances were repaid in January 2005 at a US$/C$ exchange rate of 0.8475.

In addition to the outstanding debt, letters of credit aggregating $24 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.

US dollar debt securities

On November 23, 2004, the Company issued US$350 million of US dollar debt securities maturing on December 1, 2014, bearing interest at 4.90% and US$350 million of US dollar securities maturing on February 1, 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into certain interest rate swap contracts to convert the fixed interest rate to a floating interest rate on the debt securities maturing on December 1, 2014 (note 12).

After issuing the above securities, the Company has US$1.3 billion remaining on a US$2.0 billion shelf prospectus filed in May 2003 that allows for the issue of debt securities in the United States until June 2005. If issued these securities will bear interest as determined at the date of issuance.

Preferred securities

Annual principal repayments of US$27 million are required annually commencing June 25, 2009 through June 25, 2011. The notes are subordinated to the other long-term debt of the Company and contain, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios. The Company has the unrestricted right to pay interest, principal and principal prepayment amounts by delivering common shares to the Trustee of the subordinated notes. The semi-annual interest payments may be deferred at the option of the Company for up to two consecutive periods, with a maximum of eight deferral periods over the life of the securities.

6. OTHER LONG-TERM LIABILITIES

	Dec 31 2004	Dec 31 2003
Asset retirement obligation	**$ 1,119**	$ 897
Stock-based compensation	**323**	171
Deferred revenue	**26**	-
	1,468	1,068
Less: current portion	**260**	130
	$ 1,208	$ 938

Asset retirement obligation

At December 31, 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 $3,063 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:

	Year Ended Dec 31, 2004	Year Ended Dec 31, 2003[1]
Asset retirement obligation		
Balance – beginning of year	**$ 897**	$ 867
Liabilities incurred	**339**	117
Liabilities settled	**(32)**	(40)
Asset retirement obligation accretion	**51**	62
Revision of estimates	**(86)**	(6)
Foreign exchange	**(50)**	(103)
Balance – end of year	**$ 1,119**	$ 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.

	Year Ended Dec 31, 2004	Year Ended Dec 31, 2003
Stock-based compensation		
Balance – beginning of year	**$ 171**	**$** -
Stock-based compensation provision	**259**	200
Current period expense relating to share bonus plan	**(10)**	-
Current period payment for options surrendered	**(80)**	(31)
Transferred to common shares	**(38)**	(8)
Capitalized with respect to Horizon Project	**21**	10
Balance – end of year	**323**	171
Less: current portion	**243**	130
	$ 80	**$** 41

Deferred revenue

The following table reconciles the change in deferred revenue related to derivative financial instruments:

	Deferred revenue
Fair value of financial instruments – beginning of year	**$ 40**
Amortization of deferred revenue	**(14)**
Fair value of financial instruments – end of year	**26**
Less: current portion	**17**
	$ 9

7. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Current income tax expense				
Current income tax – North America	**$ 1**	$ 3	**$ 89**	$ 43
Large corporations tax – North America	**5**	1	**11**	16
Current income tax (recovery) – North Sea	**(16)**	2	**2**	23
Current income tax – Offshore West Africa	**3**	3	**13**	10
Current income tax – other	**1**	-	**1**	-
	(6)	9	**116**	92
Future income tax expense	**258**	117	**474**	338
Income taxes	**$ 252**	$ 126	**$ 590**	$ 430

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.

8. SHARE CAPITAL

Issued

Common shares	Year ended December 31, 2004 Number of shares (thousands)[1]		Amount
Balance – beginning of year	**267,463**	**$**	**2,353**
Issued upon exercise of stock options	**1,591**		**24**
Previously recognized liability on stock options exercised for common shares	**-**		**38**
Purchase of shares under Normal Course Issuer Bid	**(873)**		**(7)**
Balance – end of year	**268,181**	**$**	**2,408**

(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 December 31, 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.

In January, 2005, 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 13,409,006 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, 2005 and ending January 23, 2006. As at February 18, 2005, the Company had not purchased any additional shares under its Normal Course Issuer Bid.

Dividend policy

On February 18, 2005, the Board of Directors set the regular quarterly dividend at $0.1125 per common share (2004 - $0.10 per common share). The Company pays regular quarterly dividends in January, April, July, and October of each year.

Stock options

	Year ended December 31, 2004		
	Stock options (thousands)[1]		Weighted average exercise price[1]
Outstanding – beginning of year	**17,789**	**$**	**19.72**
Granted	**4,861**	**$**	**35.89**
Exercised for common shares	**(1,591)**	**$**	**15.10**
Surrendered for cash settlement	**(3,781)**	**$**	**18.71**
Forfeited	**(1,017)**	**$**	**27.72**
Outstanding – end of year	**16,261**	**$**	**24.74**
Exercisable – end of year	**3,825**	**$**	**19.85**

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

9. 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.

		Dec 31 2004
Balance – beginning of year as previously reported	**$**	**17**
Change in accounting policy (note 2)		**(14)**
Balance – beginning of year as restated		**3**
Unrealized loss on translation of net investment		**(24)**
Hedge of net investment with US dollar denominated debt (net of tax)		**15**
Balance – end of year	**$**	**(6)**

10. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2004(1)	Dec 31 2003(1)	**Dec 31 2004(1)**	Dec 31 2003(1)
Weighted average common shares outstanding (thousands)				
Basic	**268,501**	267,874	**268,112**	268,470
Effect of dilutive stock options (2)	**-**	-	**-**	2,444
Assumed settlement of preferred securities with common shares	**1,950**	3,534	**2,230**	3,908
Diluted	**270,451**	271,408	**270,342**	274,822
Net earnings	**$ 577**	$ 250	**$ 1,405**	$ 1,403
Interest on preferred securities, net of tax	**1**	1	**5**	5
Revaluation of preferred securities, net of tax	**(2)**	(4)	**(4)**	(18)
Diluted net earnings	**$ 576**	$ 247	**$ 1,406**	$ 1,390
Net earnings per common share				
Basic	**$ 2.15**	$ 0.93	**$ 5.24**	$ 5.23
Diluted	**$ 2.13**	$ 0.91	**$ 5.20**	$ 5.06

(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.

11. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended		Year Ended	
	Dec 31 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Interest paid	**$ 42**	$ 31	**$ 192**	$ 178
Taxes paid				
Taxes other than income tax	**$ 27**	$ 10	**$ 151**	$ 19
Current income tax	**$ 10**	$ 14	**$ 67**	$ 32

12. 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 February 18, 2005, which includes all transactions outstanding at December 31, 2004:

	Remaining Term	Volume	Average Price	Index
Oil				
Oil price collars	Jan 2005 – Mar 2005	186,390 bbl/d	US$37.13 – US$47.21	WTI
	Apr 2005 – Jun 2005	221,000 bbl/d	US$39.41 – US$50.54	WTI
	Jul 2005 – Sep 2005	255,000 bbl/d	US$40.97 – US$51.70	WTI
	Oct 2005 – Dec 2005	255,000 bbl/d	US$40.97 – US$51.70	WTI
	Jan 2006 – Dec 2006	168,000 bbl/d	US$38.23 – US$48.24	WTI
	Jan 2006 – Dec 2006	20,000 bbl/d	C$46.53 – C$58.67	WTI
Oil puts	Jan 2005 – Mar 2005	99,000 bbl/d	US$29.21	WTI
	Apr 2005 – Jun 2005	123,000 bbl/d	US$29.89	WTI
	Jul 2005 – Sep 2005	50,000 bbl/d	US$31.09	WTI
	Oct 2005 – Dec 2005	50,000 bbl/d	US$29.81	WTI
	Jan 2007 – Dec 2007	50,000 bbl/d	US$28.00	WTI

	Remaining Term	Volume	Average Price	Index
Natural gas				
AECO collars	Jan 2005 – Mar 2005	818,000 GJ/d	C$6.07 – C$10.67	AECO
	Apr 2005 – Jun 2005	1,065,000 GJ/d	C$5.73 – C$7.73	AECO
	Jul 2005 – Sep 2005	1,065,000 GJ/d	C$5.73 – C$7.62	AECO
	Oct 2005 – Dec 2005	1,038,000 GJ/d	C$5.85 – C$8.46	AECO
	Jan 2006 – Mar 2006	700,000 GJ/d	C$5.88 – C$8.78	AECO
	Apr 2006 – Oct 2006	575,000 GJ/d	C$5.50 – C$7.09	AECO

	Remaining Term	Amount ($ millions)	Average Exchange Rate (US$/C$)
Foreign currency			
Currency collars	Jan 2005 – 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	Jan 2005 – Dec 2005	US$125	1.55	7.69%	7.30%
Currency forward	Jan 2005 – Jan 2005	US$471	1.18	n/a	n/a

	Remaining Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest rate				
Swaps – fixed to floating	Jan 2005 – Jan 2005	US$200	7.20%	LIBOR + 3.00%
	Jan 2005 – Jul 2006(1)	US$200	6.70%	LIBOR + 1.65%
	Jan 2005 – Jan 2007	US$200	7.20%	LIBOR + 2.23%
	Jan 2005 – Oct 2012	US$350	5.45%	LIBOR + 0.81%
	Jan 2005 – Dec 2014	US$350	4.90%	LIBOR + 0.38%
Swaps – floating to fixed	Jan 2005 – Mar 2007	C$10	7.36%	CDOR

(1) The above swap was unwound on January 25, 2005.

13. SEGMENTED INFORMATION

(millions of Canadian dollars, except per common share amounts, unaudited)	North America Three Months Ended December 31 2004	North America Three Months Ended December 31 2003	North America Year Ended December 31 2004	North America Year Ended December 31 2003	North Sea Three Months Ended December 31 2004	North Sea Three Months Ended December 31 2003	North Sea Year Ended December 31 2004	North Sea Year Ended December 31 2003	Offshore West Africa Three Months Ended December 31 2004	Offshore West Africa Three Months Ended December 31 2003	Offshore West Africa Year Ended December 31 2004	Offshore West Africa Year Ended December 31 2003
Revenue	**1,547**	1,069	**5,979**	5,021	**358**	235	**1,317**	953	**55**	49	**222**	155
Less: royalties	**(254)**	(172)	**(1,003)**	(868)	**-**	1	**(2)**	1	**(1)**	(2)	**(6)**	(5)
Revenue, net of royalties	**1,293**	897	**4,976**	4,153	**358**	236	**1,315**	954	**54**	47	**216**	150
Segmented expenses												
Production	**259**	203	**976**	845	**104**	73	**370**	314	**9**	9	**36**	38
Transportation	**74**	66	**256**	264	**7**	11	**32**	30	**-**	-	**-**	-
Depletion, depreciation and amortization	**407**	316	**1,444**	1,209	**81**	60	**265**	252	**11**	14	**53**	41
Asset retirement obligation accretion	**7**	7	**28**	26	**8**	9	**22**	36	**1**	-	**1**	-
Realized risk management activities	**134**	(16)	**362**	157	**41**	(1)	**112**	(9)	**-**	-	**-**	-
Total segmented expenses	**881**	576	**3,066**	2,501	**241**	152	**801**	623	**21**	23	**90**	79
Segmented earnings before taxes	**412**	321	**1,910**	1,652	**117**	84	**514**	331	**33**	24	**126**	71
Non-segmented expenses												
Administration												
Stock-based compensation												
Interest												
Unrealized risk management activities												
Foreign exchange gain												
Total non-segmented expenses												
Earnings before taxes												
Taxes other than income tax												
Current income tax (recovery) expense												
Future income tax expense												
Net earnings												

(millions of Canadian dollars, except per common share amounts, unaudited)	Midstream				Other			
	Three Months Ended December 31		Year Ended December 31		Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003	**2004**	2003	**2004**	2003
Revenue	**18**	16	**68**	61	**1**	-	**1**	-
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-
Revenue, net of royalties	**18**	16	**68**	61	**1**	-	**1**	-
Segmented expenses								
Production	**5**	4	**20**	15	**-**	-	**-**	-
Transportation	**-**	-	**-**	-	**-**	-	**-**	-
Depletion, depreciation and amortization	**2**	1	**7**	7	**-**	-	**-**	-
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-
Total segmented expenses	**7**	5	**27**	22	**-**	-	**-**	-
Segmented earnings before taxes	**11**	11	**41**	39	**1**	-	**1**	-
Non-segmented expenses								
Administration								
Stock-based compensation								
Interest								
Unrealized risk management activities								
Foreign exchange gain								
Total non-segmented expenses								
Earnings before taxes								
Taxes other than income tax								
Current income tax (recovery) expense								
Future income tax expense								
Net earnings								

(millions of Canadian dollars, except per common share amounts, unaudited)	Inter-segment Elimination				Total			
	Three Months Ended December 31		Year Ended December 31		Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003	**2004**	2003	**2004**	2003
Revenue	**(10)**	(10)	**(40)**	(35)	**1,969**	1,359	**7,547**	6,155
Less: royalties	**-**	-	**-**	-	**(255)**	(173)	**(1,011)**	(872)
Revenue, net of royalties	**(10)**	(10)	**(40)**	(35)	**1,714**	1,186	**6,536**	5,283
Segmented expenses								
Production	**-**	(1)	**(2)**	(3)	**377**	288	**1,400**	1,209
Transportation	**(10)**	(9)	**(38)**	(32)	**71**	68	**250**	262
Depletion, depreciation and amortization	**-**	-	**-**	-	**501**	391	**1,769**	1,509
Asset retirement obligation accretion	**-**	-	**-**	-	**16**	16	**51**	62
Realized risk management activities	**-**	-	**-**	-	**175**	(17)	**474**	148
Total segmented expenses	**(10)**	(10)	**(40)**	(35)	**1,140**	746	**3,944**	3,190
Segmented earnings before taxes	**-**	-	**-**	-	**574**	440	**2,592**	2,093
Non-segmented expenses								
Administration					**34**	24	**115**	87
Stock-based compensation					**26**	63	**259**	200
Interest					**48**	43	**189**	201
Unrealized risk management activities					**(317)**	-	**(40)**	-
Foreign exchange gain					**(61)**	(92)	**(91)**	(335)
Total non-segmented expenses					**(270)**	38	**432**	153
Earnings before taxes					**844**	402	**2,160**	1,940
Taxes other than income tax					**15**	26	**165**	107
Current income tax (recovery) expense					**(6)**	9	**116**	92
Future income tax expense					**258**	117	**474**	338
Net earnings					**577**	250	**1,405**	1,403

Additions to Property, Plant and Equipment

	Three Months Ended		Year Ended	
	Dec 31 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
North America	**1,398**	431	**3,782**	1,769
North Sea	**89**	106	**625**	363
Offshore West Africa	**111**	46	**296**	176
Horizon Oil Sands Project	**58**	52	**291**	152
Midstream	**11**	2	**16**	11
Head office	**8**	5	**35**	20
	$ 1,675	$ 642	**$ 5,045**	$ 2,491

	Property, Plant and Equipment		Total Assets	
	Dec 31 2004	Dec 31 2003	**Dec 31 2004**	Dec 31 2003
Segmented Assets				
North America	**$ 13,394**	$ 10,990	**$ 14,455**	$ 11,731
North Sea	**1,823**	1,437	**2,036**	1,562
Offshore West Africa	**909**	667	**922**	703
Horizon Oil Sands Project	**672**	381	**672**	381
Midstream	**209**	200	**268**	227
Head office	**57**	39	**57**	39
	$ 17,064	$ 13,714	**$ 18,410**	$ 14,643

14. SUBSEQUENT EVENT

On February 9, 2005, the Company's Board of Directors unanimously authorized the Company to proceed with Phase 1 of the Horizon Oil Sands Project. The Horizon Project is designed as a phased development and includes the mining of bitumen and an onsite upgrader. Phase 1 production is targeted to begin two components at 110,000 bbl/d of 34^{o} API light sweet, synthetic crude oil ("SCO"). Phase 2 would increase production to 155,000 bbl/d of SCO. Phase 3 would further increase production to 232,000 bbl/d of SCO. Total expected capital costs for all three phases of the development are estimated at $10.8 billion. Capital costs for the first phase of the Horizon Project are estimated at $6.8 billion including a contingency reserve of $700 million, with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008, respectively.

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 December 31, 2004:	
Interest coverage (times)	
Net earnings[1]	11.5x
Cash flow from operations[2]	21.5x

(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.

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 Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data is presented on a before royalties basis unless otherwise stated. In addition, reference is made to oil and gas in common units called barrel of oil equivalent (“boe”). A boe is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

Canadian Natural retains qualified independent reserves evaluators, to evaluate 100% of the Company's proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Canadian Natural has been granted an exemption from the National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission (SEC) requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose proved and probable reserves and future net revenues using forecast prices and costs. Canadian Natural has elected to disclose proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information. Another difference between the two standards is in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation Handbook (COGEH), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The Board of Directors of the Company has a Reserves Committee, which has met with the Company's third party reserve evaluators and carried out independent due diligence procedures with them as to the Company's reserves.

Reserves and Net Asset Values presented for years prior to 2003 were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and constant pricing as at December 31, 2004 throughout the productive life of the properties. For further information on pricing assumptions used for each year, please refer to the Company's Annual Information Form as filed on www.sedar.com, or the Company's Annual Report.

Horizon Oil Sands mining reserves have been evaluated under SEC Industry Guide 7 as at February 9, 2005. Resource potential as determined for thermal oil assets and other potential mining leases are determined using generally accepted industry methodologies for resource delineation based upon stratigraphic well drilling completed on the properties. They are not considered reserves of the Company for purposes of regulatory filings as regulatory approvals may not have been received or formal development plans may not have been approved by the Board of Directors.

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 of 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.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time on Wednesday, February 23, 2005. The North American conference call number is 1-877-888-7019 and the outside North American conference call number is 001-416-695-9753. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural Resources website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Standard Time on Wednesday, March 2, 2005. To access the postview in North America, dial 1-888-509-0081. Those outside of North America, dial 001-416-695-5275.

WEBCAST

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

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

2005 FIRST QUARTER RESULTS

2005 first quarter results are scheduled for release on Wednesday, May 4, 2005. A conference call will be held on that day at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

ANNUAL GENERAL MEETING

Canadian Natural Resources Limited's Annual General Meeting of the Shareholders will be held on Thursday, May 5, 2005 at 3:00 p.m. Mountain Daylight Time in Macleod Hall C/D, of the Telus Convention Centre, Calgary, Alberta. All shareholders are invited to attend.

For further information, please contact:

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COREY B. BIEBER
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