TSX/NYSE SYMBOL: ECA

EnCana Corporation

SECOND QUARTER INTERIM REPORT

For the period ended

June 30, 2004

Q2

ENCANA'S SECOND QUARTER OIL AND GAS PRODUCTION UP 26 PERCENT TO 775,000 BOE PER DAY; CASH FLOW EXCEEDS US$1.1 BILLION

CALGARY, ALBERTA, (JULY 27, 2004) – EnCana Corporation (TSX & NYSE: ECA) today reports production growth of more than 25 percent in the second quarter, cash flow growth surpassing 10 percent and operating earnings up more than 35 percent. Cash flow in the second quarter of 2004 was $1,131 million, or $2.43 per share diluted, up 12 percent from the same period in 2003. Operating earnings were $379 million, or $0.81 per share diluted, up 38 percent from $275 million in the second quarter of 2003 due mainly to increased sales along with stronger natural gas and oil prices. Second quarter production of oil, natural gas and natural gas liquids (NGLs) was 775,000 barrels of oil equivalent (BOE) per day, up 26 percent from the second quarter of 2003. Second quarter natural gas production was up more than 23 percent to average 3.04 billion cubic feet per day, while oil and NGLs sales rose 31 percent to 270,000 barrels of oil per day, compared to the second quarter of 2003.

EnCana reports in U.S. dollars and according to U.S. protocols in order to facilitate a more direct comparison to other North American upstream oil and natural gas exploration and development companies. Reserves and production are reported on an after-royalty basis. All figures are in U.S. dollars unless otherwise noted.

"EnCana achieved strong financial and operating performance in the second quarter, driven principally by expanded natural gas resource plays and higher crude oil production. We are on track to deliver 15 percent production growth in 2004, 80 percent of which is organic. On a per share basis, that is year-over-year production growth of about 20 percent. Looking longer term, we believe our existing asset base is capable of delivering at least 10 percent annual growth per share through the next five years," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

ENCANA™

OIL & NGLs SALES
(bbls/d)

A 31 percent sales increase was driven largely by growth in Canadian oilsands Ecuador and the U.K.

SECOND QUARTER OPERATING EARNINGS REACH $379 MILLION, UP 38 PERCENT

EnCana's second quarter operating earnings of $379 million were up 38 percent compared to the same period in 2003. Operating earnings exclude an after-tax unrealized mark-to-market loss of $104 million related to price hedges and an after-tax unrealized $25 million loss due to changes in foreign exchange on translation of U.S. dollar denominated debt issued in Canada. After inclusion of these non-cash items, net earnings in the second quarter were $250 million, or 54 cents per share diluted. Second quarter pre-tax cash flow was $1,334 million, up 40 percent from 2003. Second quarter after-tax cash flow of $1,131 million includes a cash tax provision of $203 million, compared with a $54 million cash tax recovery in 2003. This is consistent with the company's earlier statements that the merger transaction resulted in a significant cash tax deferral from 2003 to 2004. Second quarter revenues net of royalties were $2,718 million.

SECOND QUARTER GAS PRODUCTION UP 23 PERCENT IN PAST YEAR; OIL AND NGLS SALES UP 31 PERCENT

EnCana's second quarter natural gas production was 3.04 billion cubic feet per day, up 23 percent from the second quarter of 2003. The increase is mainly driven by strong growth from Greater Sierra, Cutbank Ridge and Southern Plains shallow gas in Canada and Mamm Creek in the U.S. Rockies. Gas sales include production as of May 19th from the Tom Brown acquisition, which added an average of 132 million cubic feet per day over the quarter. Oil and NGLs sales grew 31 percent to 270,000 barrels per day driven largely by growth from Canadian oilsands, Ecuador and the U.K. Operating costs were $3.29 per BOE, down 7 percent from the first quarter, and in line with the full year 2004 operating cost forecast of between $3.30 and $3.50 per BOE. EnCana drilled 1,065 net wells in the second quarter. Core capital investment, excluding acquisitions and divestitures, was approximately $1.2 billion.

SECOND QUARTER OIL AND GAS PRICE REALIZATIONS, EXCLUDING HEDGING IMPACT

EnCana's second quarter realized pre-hedging North American natural gas prices were up about 9 percent from the second quarter of 2003 to $5.34 per thousand cubic feet. Realized pre-hedging oil and NGLs prices were up about 22 percent from the second quarter of 2003 to $28.00 per barrel. Canadian heavy oil price differentials widened to average $11.02 per barrel compared to $6.55 per barrel one year earlier. Ecuadorian NAPO blend, shipped on the new OCP Pipeline, also experienced a wider price differential from WTI in the second quarter of 2004, averaging $12.17 per barrel, compared to $8.06 per barrel at year-end 2003. OCP began full operations in the fourth quarter of 2003.

GAS SALES
(MMcf/d)

Second quarter sales grew 23 percent to surpass 3 billion cubic feet per day, comprised largely of organic growth from EnCana's portfolio of North American resource plays.

PRODUCTION GROWTH ON TRACK

EnCana is on track to achieve its 2004 sales guidance of between 725,000 and 765,000 BOE per day, which at the midpoint is a 15 percent increase from 2003 sales volumes. Projected sales are comprised of between 2.95 billion and 3.05 billion cubic feet of natural gas per day and between 235,000 and 255,000 barrels of oil and NGLs per day. Upstream core capital is expected to be in the range of $4,550 million and $4,850 million for 2004.

CASH FLOW EXCEEDS $2 BILLION IN FIRST SIX MONTHS, SALES UP 20 PERCENT

EnCana's first half 2004 cash flow, before tax, was $2,561 million, up 17 percent from the same 2003 period. After-tax, EnCana generated $2,126 million of first half cash flow, or $4.55 per share diluted. This includes a first half cash tax provision of $435 million, compared with a cash tax recovery of $34 million in the first half of 2003. EnCana's first half daily sales averaged 746,500 BOE, up 20 percent from the first half of 2003. Daily sales were comprised of 2.9 billion cubic feet of gas and 267,000 barrels of oil and NGLs. In the first six months, EnCana drilled 2,684 net wells, about half of the 5,500 net wells planned for 2004.

FIRST HALF OPERATING EARNINGS WERE $844 MILLION, UP 8 PERCENT

First half 2004 operating earnings were $844 million, or $1.81 per share diluted, up about 8 percent from the first half of 2003. Net earnings in the first six months were $540 million, or $1.16 per share diluted, which includes three non-cash items: an after-tax unrealized mark-to-market loss of $356 million, an after-tax unrealized loss on foreign exchange on US$ denominated debt issued in Canada of $57 million, and a $109 million gain due to tax rate changes. First half 2004 revenues net of royalties were $5,568 million.

EARNINGS IMPACTED BY CHANGE IN ACCOUNTING POLICY FOR UNREALIZED HEDGING LOSSES

On January 1, 2004, EnCana was required to adopt the new accounting standard governing oil and gas price hedging activities. EnCana expects that this new standard will continue to result in greater volatility in its reported net earnings. A complete discussion of the impact of this new accounting standard is contained in Notes 2 and 14 of the unaudited second quarter consolidated financial statements.

RESOURCE PLAY FOCUS ADVANCED WITH TOM BROWN ACQUISITION AND CONVENTIONAL ASSET SALES

In recent months, EnCana has advanced its strategic focus on natural gas resource growth plays. These plays are characterized by long-life, low-decline production performance. With the acquisition of Tom Brown, Inc. in May, EnCana initiated a two-step process that will see its proportion of anticipated production from North American resource plays increase from 60 to approximately 75 percent during 2004. In the first step, the company acquired Tom Brown, a Denver-based, resource-play focused, gas exploration and production company. Tom Brown's assets are an excellent fit with EnCana's leading position in the Piceance Basin of the U.S. Rockies. The second step will see the divestiture of between 40,000 and 60,000 BOE per day of conventional oil and gas production. Since announcing the offer for Tom Brown in April, EnCana has reached agreements on the divestiture of about 28,000 BOE of daily production, the sale of Sauer Drilling Company of Casper, Wyoming and the divestiture of two undeveloped oilsands leases in northeast Alberta for total proceeds of about $940 million. EnCana expects to conclude these transactions by early September. Additional asset packages have been identified for divestiture in the near term. To date in 2004, EnCana has divested of, or agreed to divest of, conventional, non-core properties producing about 50,000 barrels of oil equivalent per day for total proceeds of approximately $1.35 billion.

"North American conventional reservoirs are generally experiencing increasing decline rates and decreasing reserve life – the combination of which creates a treadmill effect that makes profitable production growth difficult. EnCana's strategy of investing in unconventional North American resource plays, while divesting of conventional assets, is expected to continually slow our treadmill and enable us to focus on strong return investments in long-life, low-decline assets. Based on reserve reports prepared by independent qualified reserve evaluators at year-end 2003, the decline rate of all of EnCana's proved developed reserve base was about 20 percent, which is expected to fall to less than 15 percent over the next several years. Year-end 2004 booked reserves will reflect the acquisition of Tom Brown and the divestiture of conventional reserves, further improving this go forward picture," Morgan said.

UNBOOKED RESOURCE POTENTIAL UNDERPINS ENCANA'S LONG-TERM, RESOURCE PLAY GROWTH PLAN

Exploitation-style drilling activities and shallowing production decline profiles are characteristics of resource plays. Hence, as more and more of EnCana's production comes from the company's inventory of resource plays, the reliability and predictability of the company's resource and production growth forecasts continues to increase.

"Currently, about 17,000 long-life, shallow-decline, North American natural gas resource play wells serve as the backbone of our production, and their number continues to grow," Morgan said.

Reported proved reserves at year-end 2003 were about 2.4 billion BOE, yielding a reserve life index of about 8.5 years based on current production rates, which excludes proved reserves that have since been added via ongoing field activities and the Tom Brown acquisition. Beyond that, EnCana estimates that 3.5 billion BOE of Unbooked Resource Potential may be added to proved reserves over the next five years. This Unbooked Resource Potential is largely associated with our resource plays and therefore EnCana's investments are mainly focused on low-risk exploitation rather than high risk exploration.

EnCana estimates this Unbooked Resource Potential to be about 16 trillion cubic feet of natural gas and about 850 million barrels of oil and natural gas liquids, up approximately 60 percent over the past year due mainly to the addition of the Cutbank Ridge resource play in British Columbia and the Tom Brown acquisition. This means that, after production, proved reserves on existing company lands are expected to increase about 75 percent over the next five years. EnCana also has substantial conventional exploration potential on its 20 million net acres of undeveloped North American land that is not included in its assessment of its Unbooked Resource Potential.

"It is the repeatable nature of the low-risk exploitation of both our proved reserves and Unbooked Resource Potential that enables us to confidently say that we expect our future production growth to average an annual rate of at least 10 percent per share. In fact, we are projecting our gas production will grow by 35 percent over the two-year period 2003 to 2005. This projected resource play growth stands in stark contrast to weakening industry-wide, conventional natural gas and oil production in North America," Morgan said.

RISK MANAGEMENT STRATEGY

EnCana's market risk mitigation strategy is designed to deliver greater predictability of cash flow and returns on investment. Approximately half of the company's projected 2004 gas sales, after royalties, is hedged at an average effective NYMEX price of about $5.36 per thousand cubic feet. In addition, the company has entered into longer term basis and pricing hedges specifically for the purpose of protecting against high U.S. Rockies gas price basis differentials. About half of EnCana's projected 2004 oil sales are hedged with swaps or costless collars between $20 and $26 per barrel of WTI. Detailed risk management positions at June 30, 2004 are presented in Note 14 to the unaudited second quarter consolidated financial statements for the financial contracts and in Management's Discussion and Analysis for the physical contracts. In the second quarter, EnCana's financial commodity and currency risk management measures resulted in gross revenue being lower by approximately $234 million, comprised of $164 million on oil sales and $70 million on gas sales.

FINANCIAL HIGHLIGHTS

US$ and U.S. protocols

Consolidated EnCana Highlights

(as at and for the period ended June 30) *(US$ millions, except per share amounts)*	**Q2 2004**	Q2 2003	% Δ	**6 months 2004**	6 months 2003	% Δ
REVENUES, NET OF ROYALTIES	**2,718**	2,332	+17	**5,568**	5,075	+10
OPERATING EBITDA [1]	**1,399**	1,016	+38	**2,704**	2,289	+18
Cash flow	**1,131**	1,007	+12	**2,126**	2,228	–5
Per share – basic	**2.46**	2.10	+17	**4.62**	4.64	–
Per share – diluted	**2.43**	2.08	+17	**4.55**	4.61	–1
Add back:						
CASH TAX	**203**	(54)	n/a	**435**	(34)	n/a
PRE-TAX CASH FLOW	**1,334**	953	+40	**2,561**	2,194	+17
CAPITAL INVESTMENT						
Core capital	**1,201**	862	+39	**2,605**	1,843	+41
Net acquisitions and divestitures	**2,235**	208	+975	**2,056**	347	+493
Net capital investment – continuing operations	**3,436**	1,070	+221	**4,661**	2,190	+113
NET EARNINGS	**250**	807	–69	**540**	1,644	–67
Per share – basic	**0.54**	1.68	–68	**1.17**	3.42	–66
Per share – diluted	**0.54**	1.67	–68	**1.16**	3.40	–66
NET EARNINGS FROM CONTINUING OPERATIONS	**250**	805	–69	**540**	1,455	–63
Per share – basic	**0.54**	1.67	–68	**1.17**	3.03	–61
Per share – diluted	**0.54**	1.66	–67	**1.16**	3.01	–61
Add back:						
Mark-to-market price hedging impact, after-tax	**104**	–	n/a	**356**	–	n/a
Add back:						
Foreign exchange translation of U.S. dollar debt issued in Canada, after-tax	**25**	(168)	–115	**57**	(308)	–119
Less:						
Tax rate change	**–**	(362)	n/a	**(109)**	(362)	–70
OPERATING EARNINGS	**379**	275	+38	**844**	785	+8
Per share – basic	**0.82**	0.57	+44	**1.83**	1.63	+12
Per share – diluted	**0.81**	0.56	+45	**1.81**	1.62	+12
COMMON SHARES at June 30 *(millions)*						
Weighted average (basic)	**460.3**	**480.6**	–4	**460.6**	**480.3**	–4
Weighted average (diluted)	**465.5**	**484.4**	–4	**466.8**	**483.8**	–4

[1] Operating EBITDA is net earnings from continuing operations before interest, income taxes, depreciation, depletion and amortization (DD&A), accretion of asset retirement obligation, foreign exchange loss (gain), gain on disposition and unrealized loss on risk management ($531 million, year-to-date, before tax).

OPERATING HIGHLIGHTS

Consolidated EnCana Highlights

(for the period ended June 30) (After royalties)	**Q2 2004**	Q2 2003	% Δ	**6 months 2004**	6 months 2003	% Δ
Natural gas *(MMcf/d)*						
Production (excluding TBI)	**2,905**	2,469	+18	**2,810**	2,468	+14
TBI production	**132**	–	n/a	**65**	–	n/a
Produced gas withdrawn from storage	–	–	–	–	60	n/a
Total natural gas sales *(MMcf/d)*	**3,037**	2,469	+ 23	**2,875**	2,528	+ 14
Oil and NGLs sales *(bbls/d)*						
North America	**170,687**	159,668	+ 7	**168,283**	157,991	+7
International	**99,031**	46,240	+ 114	**99,051**	44,073	+ 125
Total oil and NGLs sales *(bbls/d)*	**269,718**	205,908	+ 31	**267,334**	202,064	+32
Total sales *(BOE/d)*	**775,885**	617,408	+ 26	**746,501**	623,397	+20
Per share sales growth			+ 31			+ 26

Resource plays continue to deliver strong growth

In North America, EnCana's growth continues to be delivered from its low decline resource plays. Second quarter oil and gas production from EnCana's key North American resource plays has increased more than 33 percent since the second quarter of 2003. This was driven principally by increases in gas production at Mamm Creek in Colorado, Greater Sierra in northeast B.C., and Southern Plains shallow gas on legacy Suffield and Palliser Blocks in southern Alberta, plus increases in oil production at Foster Creek and Pelican Lake in northeast Alberta.

GROWTH FROM KEY NORTH AMERICAN RESOURCE PLAYS

Resource Play

	Daily Production							Net Wells Drilled			
	2004			2003				**2004**			2003
	YTD	**Q2**	Q1	Q4	Q3	Q2	Q1	**YTD**	**Q2**	Q1	Full year
Natural gas (*MMcf/d*)											
Canada											
Southern Plains shallow gas	**572**	**590**	554	538	509	499	483	**946**	**416**	530	2,366
Greater Sierra	**231**	**247**	216	175	144	136	118	**156**	**21**	135	199
Cutbank Ridge	**32**	**41**	22	6	2	2	2	**21**	**4**	17	20
Coalbed methane	**10**	**11**	10	7	3	3	2	**179**	**98**	81	267
U.S.A.											
Jonah	**390**	**387**	394	389	376	356	375	**32**	**21**	11	59
Mamm Creek	**197**	**203**	191	175	126	112	86	**131**	**65**	66	259
North Texas	**22**	**23**	21	19	12	–	–	**18**	**10**	8	5
Oil *(Mbbls/d) (Canada)*											
Foster Creek	**29**	**30**	28	26	22	20	19	**4**	**–**	4	8
Pelican Lake	**15**	**15**	15	15	16	17	15	**59**	**30**	29	134

CORPORATE DEVELOPMENTS

Dividend $0.10 per share

EnCana's board of directors has declared a quarterly dividend of $0.10 per share payable on September 30, 2004 to common shareholders of record as of September 15, 2004.

Normal Course Issuer Bid purchases

To date in 2004, EnCana has purchased for cancellation 5.5 million of its shares at an average price of C$55.37 per share under its current Normal Course Issuer Bid and 5.9 million shares were issued to employees under the company's stock option plan. The company had approximately 461.0 million shares outstanding at June 30, 2004.

FINANCIAL STRENGTH

Balance Sheet Highlights

(US$ millions, except percent and ratio amounts)	**June 30 2004**	December 31 2003
Total assets	**28,976**	24,110
Long-term debt	**8,582**	6,088
Shareholders' equity	**11,405**	11,278
Net debt-to-capitalization ratio	**45%**	34%
(Pro forma impact of announced third quarter asset sales)		
Long-term debt	**7,642**	n/a
Net debt-to-capitalization ratio	**43%**	n/a
Debt/Trailing EBITDA	**2.0 times**	n/a

Following the announcement of the all cash Tom Brown acquisition, credit rating agencies adjusted EnCana's long term credit ratings. On July 14, 2004, Moody's lowered EnCana's rating from Baa1 to Baa2 (Stable). Standard and Poor's modified EnCana's A- rating noting that the company is under a "CreditWatch with negative implications." Its review is ongoing. Dominion Bond Rating Service has confirmed EnCana's A(low) rating noting a trend change from "Stable" to "Negative." EnCana has ongoing discussions with the rating agencies to update them on general corporate matters including the positive balance sheet impact of current and planned divestiture programs. The company also has a $3 billion committed credit facility with a syndicate of major banks and lending institutions, of which about $850 million remains unutilized. To fund the Tom Brown acquisition, EnCana arranged a further $3 billion non-revolving bridge financing. The financing was reduced to $1.8 billion, of which $1.74 billion was drawn. On May 13, EnCana Holdings Finance Corp., an EnCana subsidiary, completed a public offering for $1 billion, 5.8% Notes due 2014, to fund the remaining cash requirement for the Tom Brown acquisition.

In the second quarter of 2004, EnCana invested $1,201 million of core capital, acquisitions totaled $2,341 million and divestitures were $106 million, resulting in net capital investment of $3,436 million. This includes the Tom Brown acquisition cost. Subsequent to the end of the second quarter, agreements were reached on asset sales totaling about $660 million. Additional asset sales are expected in the near term.

ENCANA 2004 CAPITAL INVESTMENT FORECAST

Figures are based on midpoint of the ranges outlined in EnCana's capital investment guidance

		(US$ MM)
Upstream		
Core capital		4,700
Acquisition of Tom Brown		2,700
Acquisitions and Divestitures		
Divestitures, completed and pending		
Petrovera	(288)	
New Mexico assets	(243)	
July 15 oil assets	(395)	
July 20 gas assets	(219)	
Other minor sales	(195)	
	(1,340)	(1,340)
Acquisitions, minor		140
Planned additional divestitures		(550)
		(1,750)
Total Upstream net capital		5,650
Midstream, marketing & corporate		150
Net capital investment		**5,800**

Non-GAAP measures

This news release contains references to cash flow, pre-tax cash flow, operating EBITDA (net earnings from continuing operations before interest, income taxes, DD&A, accretion of asset retirement obligation, foreign exchange loss (gain), gain on disposition and unrealized loss on risk management), EBITDA and operating earnings, and the related basic and diluted per common share amounts as applicable, which are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this press release in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

EnCana Corporation

With an enterprise value of approximately $28 billion, EnCana is one of the world's leading independent oil and gas companies and North America's largest independent natural gas producer and gas storage operator. Ninety percent of the company's assets are located in North America. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. Through its U.S. subsidiaries, EnCana is one of the largest gas explorers and producers in the Rocky Mountain states and has a strong position in the deep water Gulf of Mexico. International subsidiaries operate two key high potential international growth regions: Ecuador, where it is the largest private sector oil producer, and the U.K., where it is the operator of a large oil discovery. EnCana and its subsidiaries also conduct high upside potential new ventures exploration in other parts of the world. EnCana is driven to be the industry's high performance benchmark in production cost, per-share growth and value creation for shareholders. EnCana Common Shares trade on the Toronto and New York stock exchanges under the symbol ECA.

ADVISORY REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION – EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). EnCana's reserves quantities represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Natural gas volumes that have been converted to barrels of oil equivalent (BOEs) have been converted on the basis of six thousand cubic feet (mcf) to one barrel (bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

EnCana Corporation resource descriptions

EnCana uses the terms resource play, estimated ultimate recovery, resource potential and Unbooked Resource Potential. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery (EUR) has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. Resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves over a specified period of time largely from a specified resource play or plays. EnCana's current stated estimates of Unbooked Resource Potential uses a five year time frame for their specified period of time.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this news release are forward-looking statements within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements in this news release include, but are not limited to: production, sales and growth estimates for crude oil, natural gas and NGLs for 2004 and the next 5 years, including estimates calculated on a per share basis; the Company's projections with respect to the percentage of production from resource plays in the future and the impact of increasing the Company's proportion of resource play assets on future decline rates and the reliability and predictability of resource and production growth; the resource potential, Unbooked Resource Potential, production and growth potential, including the Company's plans therefor, and capital costs associated therewith with respect to EnCana's various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea, the Gulf of Mexico and potential international exploration; estimates of resource life; the Company's projections relating to regulatory approvals; potential dispositions of assets in 2004 and beyond, including anticipated proceeds therefrom and the dates for receipt thereof; the Company's projected capital investment levels for 2004 and 2005, and the source of funding therefor; projected additional production from the Tom Brown, Inc. acquisition and the impact on production levels of proposed asset dispositions; the effect of the Company's risk management program, including the impact of derivative financial instruments; projected levels of hedging for Tom Brown, Inc. production in 2004 through 2006; the Company's projections for reductions in net debt and net debt to capitalization by the end of 2004; projected operating and administrative costs for 2004; projected DD&A rates for 2004 and beyond; projected levels of, and volatility of, crude oil and natural gas prices in 2004 and beyond and the potential causes therefor, including the impact which weather, the timing of new production, economic activity levels and political instability may have on commodity prices in the near term; projected tax rates and projected current taxes payable for 2004 and the impact of future unrealized foreign exchange gains and losses thereon and the adequacy of the Company's provision for taxes; the impact of the AEUB ruling on natural gas production for 2004 and beyond; projections with respect to the number of wells drilled and well tie-ins made in 2004; the impact of new oil and natural gas price hedging accounting standards, including their impact on the volatility of future reported net earnings; Unbooked Resource Potential which may be recognized as proved reserves in the future; projections with respect to anticipated future cash flow levels; projections with respect to potential future drilling and service cost escalations and the impact of the Company's divestitures and potential divestitures on operating costs, netbacks and decline rates. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves; the Company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's ability to secure adequate product transportation; changes in environmental and other regulations; political and economic conditions in the countries in which the Company operates, including Ecuador; the risk of war, hostilities, civil insurrection and instability affecting countries in which the Company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

Furthermore, the forward-looking statements contained in this news release are made as of the date of this news release, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company and its subsidiaries, certain statements throughout this Management's Discussion and Analysis ("MD&A") constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: production and sales estimates for crude oil, natural gas and NGLs for 2004; the Company's projections with respect to the percentage of production from resource plays in the future; the production and growth potential, including the Company's plans therefor, with respect to EnCana's various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea, the Gulf of Mexico and potential international exploration; potential dispositions of assets in 2004, including anticipated proceeds therefrom and the dates for receipt thereof; the Company's projected capital investment levels for 2004 and the source of funding therefor; projected additional production from the Tom Brown, Inc. acquisition and the impact on production levels of proposed asset dispositions; the effect of the Company's risk management program, including the impact of derivative financial instruments; projected levels of hedging for Tom Brown, Inc. production in 2004 through 2006; the Company's execution of share purchases under its Normal Course Issuer Bid; the Company's defence of lawsuits; the Company's projected ability to extend its debt program on an ongoing basis; the Company's projections for reductions in net debt prior to the end of 2004; projected operating costs for 2004; the impact of the Kyoto Accord and similar initiatives in the U.S.A. on operating costs; projected volatility of crude oil prices in 2004 and the potential causes therefore, including the impact which weather, the timing of new production, economic activity levels, OPEC actions and political instability may have on commodity prices in the near term; projected tax rates and projected current taxes payable for 2004 and the impact of future unrealized foreign exchange gains and losses thereon and the adequacy of the Company's provision for taxes; the impact of the AEUB ruling on natural gas production for 2004 and beyond and projected sensitivities of 2005 net earnings and cash flow.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in environmental and other regulations; political and economic conditions in the countries in which the Company and its subsidiaries' operate, including Ecuador; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions brought against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

NOTE REGARDING OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 ("NI 51-101"). The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Natural Gas Conversions

Natural gas volumes that have been converted to barrels of oil equivalent ("BOE(s)") have been converted on the basis of six thousand cubic feet ("Mcf") to one barrel ("bbl"). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head. Natural gas volumes are also often presented in million cubic feet ("MMcf"). Natural gas volumes are sold based on heat content in British Thermal Units ("Btu's") but physically measured in standard cubic feet ("scf"). The heat content of natural gas varies by formation and therefore by production region. For example, the heat content of EnCana's natural gas production in Alberta is approximately 1,020 Btu/scf and the U.S. Rockies is approximately 1,110 Btu/scf. The average heat content of EnCana's natural gas production in total is approximately 1,040 Btu/scf or 1.04 million British Thermal Units ("MMBtu")/Mcf.

Resource Play, Estimated Ultimate Recovery and Resource Potential
EnCana uses the terms resource play, estimated ultimate recovery and resource potential. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. Resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves over a specified period of time largely from a specified resource play or plays. EnCana's current stated estimates of unbooked resource potential utilizes a five year time frame for their specified period of time.

NOTE REGARDING CURRENCY, PROTOCOLS AND NON-GAAP MEASURES

All information included in this MD&A and the Interim Consolidated Financial Statements and comparative information is shown on a US dollar, after royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.73 for every Canadian dollar.

Non-GAAP Measures
Certain measures in this MD&A do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow from Continuing Operations per share-basic, Cash Flow from Continuing Operations per share-diluted, Cash Flow per share-basic and Cash Flow per share-diluted, Operating Earnings and Earnings Before Interest, Taxes, Depreciation Depletion and Amortization ("EBITDA") and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in this MD&A as these measures are discussed and presented.

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the unaudited interim Consolidated Financial Statements ("Interim Consolidated Financial Statements") for the three and six months ended June 30, 2004, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2003. The Interim Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian GAAP in the currency of the United States (except where indicated as being in another currency). The production and sales volumes in this MD&A and the supplementary information in the Interim Consolidated Financial Statements, have been presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated July 26, 2004.

OVERVIEW

SUMMARY OF KEY EVENTS AND KEY FINANCIAL RESULTS IN THE SECOND QUARTER

Second quarter 2004 compared to second quarter 2003:

- Successful acquisition of Tom Brown, Inc. ("TBI") on May 19, 2004 for approximately $2.7 billion including acquired debt of approximately $0.4 billion.
- Upstream sales volumes increased by 26 percent to 775,885 BOE per day primarily as a result of the Company's successful drilling programs and tie-ins on resource play assets in North America, the commencement of shipments in September 2003 on the OCP Pipeline in Ecuador and the acquisitions of TBI, as well as properties in the U.K. North Sea.
- Realized North American natural gas prices, net of royalties (excluding financial hedges), are $5.34 per Mcf in 2004 compared to $4.88 per Mcf in 2003, higher by $0.46 per Mcf. Realized liquids prices, net of royalties (excluding financial hedges), are $28.00 per barrel in 2004 compared to $22.93 in 2003, higher by $5.07 per barrel. Realized financial hedge losses are approximately $234 million in 2004 (comprised of $0.25 per Mcf on natural gas and $6.69 per barrel on liquids) compared to $87 million for 2003 (comprised of $0.25 per Mcf on natural gas and $1.61 per barrel on liquids).
- Mark-to-market accounting for derivative instruments resulted in a $155 million ($104 million after-tax) charge to earnings for unrealized losses in 2004 with no corresponding amount in 2003.
- A $32 million ($25 million after-tax) charge to earnings for unrealized losses on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $211 million ($168 million after-tax) in 2003 as a result of a relatively stable U.S./Canadian dollar exchange rate in 2004 compared to significant appreciation of the Canadian dollar against the U.S. dollar in the same period in 2003.
- Current income tax provision increased to $203 million in 2004 compared to a tax recovery of $54 million in 2003, for a total increase in cash taxes of $257 million.
- Common shares outstanding decreased by approximately 4 percent to 461 million shares as a result of the Company's share buyback program.

Further discussion and analysis follows in this MD&A on the items noted above in the "Continuing Alignment of North American Assets with EnCana's Resource Play Strategy", "Consolidated Financial Results" and "Results of Operations" sections immediately following this "Overview" as well as in the "Liquidity and Capital Resources", "Business Environment" and "Outlook" sections located towards the end of this MD&A.

CONTINUING ALIGNMENT OF NORTH AMERICAN ASSETS WITH ENCANA'S RESOURCE PLAY STRATEGY

With the acquisition of Tom Brown, Inc. and increased asset sales, the Company is accelerating its strategy of increasing production from resource plays and moving away from conventional plays in North America. The Company has estimated its North American production will be derived approximately 75 percent from resource plays and 25 percent from conventional production when these transactions have been completed.

ACQUISITION OF TOM BROWN, INC.

On May 19, 2004, the Company successfully completed its cash tender offer for all the outstanding Common Shares of TBI which became an indirect wholly owned subsidiary following the merger of TBI and another of the Company's indirect wholly owned subsidiaries on May 24, 2004. The total consideration was approximately $2.7 billion including the acquired debt of TBI. The TBI assets are primarily strong growth, long-life North American resource play assets which complement existing Company assets and are consistent with management's strategic focus. The impact of this acquisition on the Company's second quarter and year-to-date results is as follows:

TBI Acquisition Impact Summary

	Acquisition Date to June 30[1] **2004**	Three Months Ended June 30 **2004**	Six Months Ended June 30 **2004**
Volumes:			
Natural Gas *(MMcf per day)*	279	132	65
Oil *(barrels per day)*	468	221	111
NGLs *(barrels per day)*	6,304	2,979	1,490
Total Volumes *(MMcf equivalent per day)*	320	151	75
Total Volumes *(BOE per day)*	53,330	25,200	12,435
Operating Expense *(per BOE)*	$ 3.67	$ 3.67	$ 3.67
Purchase Price: *(millions)*			
Purchase Price	$ 2,747		
Long-Term-Debt of TBI acquired	(406)		
Cash Consideration [2]	$ 2,341		

(1) Date of acquisition was May 19, 2004 or 43 days in the second quarter.

(2) Excludes transaction costs of approximately $13 million and includes acquired cash of $19 million.

In conjunction with the acquisition, the Company has hedged all of the forecasted production from the TBI U.S. assets at a New York Mercantile Exchange ("NYMEX") equivalent price of approximately $5.60 per Mcf for the last six months of 2004 as well as for all of 2005 and 2006.

2004 DISPOSITIONS

In line with the Company's strategy of focusing on its inventory of North American resource play assets, the Company announced the planned disposition of Canadian conventional producing assets. Under the revised guidance for 2004 issued June 15, 2004, the Company expects to receive total proceeds of between approximately $1.5 billion to $2.0 billion for 2004 dispositions, net of minor acquisitions. The following table represents the completed and announced dispositions of assets as of the date of this MD&A:

Month	Closing Date	Disposition Description	$ millions [1]
February	February	Petrovera partnership interest [2]	$ 288
January to June	January to June	Miscellaneous properties and other	131
		Completed Dispositions	**419**
June	Third quarter	New Mexico and west Texas	243
June	Third quarter	Drilling company	35
July	Third quarter	Western Canadian properties	660
		Total	**$ 1,357**

(1) Transactions which have not closed are subject to post closing adjustments.

(2) Represents net proceeds (Acquisition of $253 and disposition of $541 million).

CONSOLIDATED FINANCIAL RESULTS

Consolidated Financial Summary

($ millions, except per share amounts)	Three Months Ended June 30 2004	2004 vs 2003	2003	Six Months Ended June 30 2004	2004 vs 2003	2003	Year Ended 2003
Revenues, Net of Royalties	**$ 2,718**	**17%**	$ 2,332	**$ 5,568**	**10%**	$ 5,075	$ 10,216
Net Earnings from Continuing Operations	**250**	**–69%**	805	**540**	**–63%**	1,455	2,167
– per share – basic	**0.54**	**–68%**	1.67	**1.17**	**–61%**	3.03	4.57
– per share – diluted	**0.54**	**–67%**	1.66	**1.16**	**–61%**	3.01	4.52
Net Earnings	**250**	**–69%**	807	**540**	**–67%**	1,644	2,360
– per share – basic	**0.54**	**–68%**	1.68	**1.17**	**–66%**	3.42	4.98
– per share – diluted	**0.54**	**–68%**	1.67	**1.16**	**–66%**	3.40	4.92
Operating Earnings (1)	**379**	**38%**	275	**844**	**8%**	785	1,375
– per share – diluted	**0.81**	**45%**	0.56	**1.81**	**12%**	1.62	2.87
Cash Flow from Continuing Operations	**1,131**	**9%**	1,039	**2,126**	**–5%**	2,230	4,420
– per share – basic	**2.46**	**14%**	2.16	**4.62**	**0%**	4.64	9.32
– per share – diluted	**2.43**	**14%**	2.14	**4.55**	**–1%**	4.61	9.21
Cash Flow	**1,131**	**12%**	1,007	**2,126**	**–5%**	2,228	4,459
– per share – basic	**2.46**	**17%**	2.10	**4.62**	**0%**	4.64	9.41
– per share – diluted	**2.43**	**17%**	2.08	**4.55**	**–1%**	4.61	9.30

(1) Operating Earnings is a non-GAAP measure and is described and discussed under "Operating Earnings" in this MD&A.

Quarterly Summary

($ millions, except per share amounts)	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3
Revenues, Net of Royalties	**$ 2,718**	$ 2,850	$ 2,850	$ 2,291	$ 2,332	$ 2,743	$ 2,116	$ 1,780
Net Earnings from Continuing Operations	**250**	290	426	286	805	650	248	79
– per share – basic	**0.54**	0.63	0.92	0.60	1.67	1.35	0.52	0.17
– per share – diluted	**0.54**	0.62	0.91	0.60	1.66	1.34	0.51	0.16
Net Earnings	**250**	290	426	290	807	837	282	136
– per share – basic	**0.54**	0.63	0.92	0.61	1.68	1.74	0.59	0.29
– per share – diluted	**0.54**	0.62	0.91	0.61	1.67	1.73	0.58	0.28
Operating Earnings (1)	**379**	465	316	274	275	510	239	188
– per share – diluted	**0.81**	1.00	0.68	0.57	0.56	1.05	0.49	0.39
Cash Flow from Continuing Operations	**1,131**	995	1,217	973	1,039	1,191	874	583
– per share – basic	**2.46**	2.16	2.63	2.06	2.16	2.48	1.83	1.22
– per share – diluted	**2.43**	2.13	2.61	2.04	2.14	2.46	1.81	1.21
Cash Flow	**1,131**	995	1,254	977	1,007	1,221	935	651
– per share – basic	**2.46**	2.16	2.71	2.06	2.10	2.54	1.96	1.37
– per share – diluted	**2.43**	2.13	2.69	2.04	2.08	2.52	1.94	1.35

(1) Operating Earnings is a non-GAAP measure and is described and discussed under "Operating Earnings" in this MD&A.

CASH FLOW

EnCana's cash flow from continuing operations increased $92 million, or $0.30 per share diluted in the second quarter of 2004 compared to the same period in 2003 and decreased $104 million, or $0.06 per share diluted during the first six months of 2004 compared to the first six months in 2003. Significant items are as follows:

Second quarter 2004 compared to second quarter 2003:

- Natural gas sales volumes increased 23 percent to 3,037 MMcf per day.
- Crude oil and NGLs sales volumes increased 31 percent to 269,718 barrels per day.
- Current tax provision increased by $257 million partially offsetting increased cash flow from higher volumes.
- Realized North American natural gas prices, net of royalties (excluding financial hedges), are $5.34 per Mcf in 2004 compared to $4.88 per Mcf in 2003, higher by $0.46 per Mcf.
- Realized liquids prices, net of royalties (excluding financial hedges), are $28.00 per barrel in 2004 compared to $22.93 in 2003, higher by $5.07 per barrel.
- Realized financial hedge losses are approximately $234 million in 2004 (comprised of $0.25 per Mcf on natural gas and $6.69 per barrel on liquids) compared to $87 million for 2003 (comprised of $0.25 per Mcf on natural gas and $1.61 per barrel on liquids).

Six months ended June 2004 compared to six months ended June 2003:

- Crude oil and NGLs sales volumes increased 32 percent to 267,334 barrels per day.
- Natural gas sales volumes increased 14 percent to 2,875 MMcf per day.
- Current tax provision increased by $469 million partially offsetting increased cash flow from higher volumes.
- Realized North American natural gas prices, net of royalties (excluding financial hedges), are $5.30 per Mcf in 2004 compared to $5.19 per Mcf in 2003, higher by $0.11 per Mcf.
- Realized liquids prices, net of royalties (excluding financial hedges), are $26.63 per barrel in 2004 compared to $24.86 in 2003, higher by $1.77 per barrel.
- Realized financial hedge losses are approximately $383 million in 2004 (comprised of $0.17 per Mcf on natural gas and $6.04 per barrel on liquids) compared to $225 million for 2003 (comprised of $0.25 per Mcf on natural gas and $3.00 per barrel on liquids).

Cash flow is a non-GAAP measure but is commonly used in the oil and gas industry to assist management and investors to measure the Company's ability to finance its capital programs and meet its credit obligations. The calculation of cash flow is disclosed on the Consolidated Statement of Cash Flows in the Interim Consolidated Financial Statements.

NET EARNINGS

EnCana's net earnings from continuing operations decreased $555 million, or $1.12 per share diluted in the second quarter of 2004 compared to the same period in 2003 and decreased $915 million, or $1.85 per share diluted during the first six months of 2004 compared to the first six months in 2003. In addition to the items affecting cash flow as detailed previously in this MD&A, significant items are:

Second quarter 2004 compared to second quarter 2003:

- Mark-to-market accounting for derivative instruments resulted in a $155 million ($104 million after-tax, $0.22 per share diluted) charge to earnings for unrealized losses in 2004 with no corresponding amount in 2003.
- A $32 million ($25 million after-tax, $0.05 per share diluted) charge to earnings for unrealized losses on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $211 million ($168 million after-tax, $0.35 per share diluted) in 2003 as a result of a relatively stable U.S./Canadian dollar exchange rate in 2004 compared to significant appreciation of the Canadian dollar against the U.S. dollar in the same period in 2003.
- The inclusion of a gain due to a change in tax rates of $362 million, or $0.75 per share diluted, in 2003.

Six months ended June 2004 compared to six months ended June 2003:

- Unrealized mark-to-market losses of $531 million ($356 million after-tax, $0.76 per share diluted) are included in 2004 with no corresponding amount in 2003.
- Included in 2004 is a gain due to a change in tax rates of $109 million or $0.23 per share diluted, compared to $362 million, or $0.75 per share diluted, in 2003.

- A $71 million ($57 million after-tax, $0.12 per share diluted) charge to earnings for unrealized losses on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $389 million ($308 million after-tax, $0.64 per share diluted) in 2003 as a result of a decrease in the period-end U.S./Canadian dollar exchange rate between December 31, 2003 and June 30, 2004 compared to significant appreciation in the period-end U.S./Canadian dollar exchange rate between December 31, 2002 and June 30, 2003.

Net earnings in 2003 include $189 million, or $0.39 per share diluted from discontinued operations.

Impacts on results due to the change in the U.S./Canadian dollar exchange rate need to be considered when analyzing specific components contained in the Interim Consolidated Financial Statements. For every 100 dollars denominated in Canadian currency spent on capital projects, operating expenses and administrative expenses, the Company incurred additional costs, as reported in U.S. dollars, of approximately $2.10 based on the increase in the average U.S./Canadian dollar exchange rate in the second quarter of 2004 of $0.736 compared to the second quarter of 2003 of $0.715. On a year-to-date basis, for every 100 dollars denominated in Canadian currency spent on capital projects, operating expenses and administrative expenses, the Company incurred additional costs, as reported in U.S. dollars, of approximately $5.80 based on the increase in the average U.S./Canadian dollar exchange rate in 2004 of $0.747 compared to 2003 of $0.689. Revenues for the Company were relatively unaffected by the increased exchange rate since commodity prices received are largely based in U.S. dollars or in Canadian dollar prices which are closely tied to the value of the U.S. dollar.

OPERATING EARNINGS

Operating earnings is a non-GAAP measure that shows net earnings from continuing operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates. The following table has been prepared in order to provide shareholders and potential investors with information clearly presenting the effect on the Company's results of mark-to-market accounting for derivative financial instruments, the translation of the outstanding U.S. dollar debt issued in Canada and the effect of the reduction in the Canadian and Alberta tax rates. Management believes these items reduce the comparability of the Company's underlying financial performance between periods. The majority of the unrealized gains/losses on U.S. dollar debt issued in Canada relate to debt with maturity dates in excess of five years.

Quarterly Summary of Operating Earnings

	2004		2003				2002	
($ millions)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Net Earnings from Continuing Operations, as reported	**$ 250**	$ 290	$ 426	$ 286	$ 805	$ 650	$ 248	$ 79
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**104**	252	–	–	–	–	–	–
Add: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar debt (after-tax)	**25**	32	(113)	(12)	(168)	(140)	(6)	100
Add: Future tax (recovery) expense due to tax rate reductions	**–**	(109)	3	–	(362)	–	(3)	9
Operating Earnings (1)(3)	**$ 379**	$ 465	$ 316	$ 274	$ 275	$ 510	$ 239	$ 188
($ per Common Share – Diluted)								
Net Earnings from Continuing Operations, as reported	**$ 0.54**	$ 0.62	$ 0.91	$ 0.60	$ 1.66	$ 1.34	$ 0.51	$ 0.16
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**0.22**	0.54	–	–	–	–	–	–
Add: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar debt (after-tax)	**0.05**	0.07	(0.24)	(0.03)	(0.35)	(0.29)	(0.01)	0.21
Add: Future tax (recovery) expense due to tax rate reductions	**–**	(0.23)	0.01	–	(0.75)	–	(0.01)	0.02
Operating Earnings (1)(3)	**$ 0.81**	$ 1.00	$ 0.68	$ 0.57	$ 0.56	$ 1.05	$ 0.49	$ 0.39

Year-to-Date Summary of Operating Earnings

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	**2004**	**2004 vs 2003**	2003	**2004**	**2004 vs 2003**	2003
Net Earnings from Continuing Operations, as reported	**$ 250**	**–69%**	$ 805	**$ 540**	**–63%**	$ 1,455
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**104**	**–**	–	**356**	**–**	–
Add: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar debt (after-tax)	**25**	**–115%**	(168)	**57**	**–119%**	(308)
Add: Future tax (recovery) expense due to tax rate reductions	**–**	**–100%**	(362)	**(109)**	**–70%**	(362)
Operating Earnings (1)(3)	**$ 379**	**38%**	$ 275	**$ 844**	**8%**	$ 785
($ per Common Share – Diluted)						
Net Earnings from Continuing Operations, as reported	**$ 0.54**	**–67%**	$ 1.66	**$ 1.16**	**–61%**	$ 3.01
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**0.22**	**–**	–	**0.76**	**–**	–
Add: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar debt (after-tax)	**0.05**	**–114%**	(0.35)	**0.12**	**–119%**	(0.64)
Add: Future tax (recovery) expense due to tax rate reductions	**–**	**–100%**	(0.75)	**(0.23)**	**–69%**	(0.75)
Operating Earnings (1)(3)	**$ 0.81**	**45%**	$ 0.56	**$ 1.81**	**12%**	$ 1.62

(1) Operating Earnings is a non-GAAP measure that shows net earnings from continuing operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the (gain)/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

(2) The Company adopted mark-to-market accounting on derivative financial instruments prospectively January 1, 2004. See Note 2 of the Interim Consolidated Financial Statements.

(3) Unrealized (gains)/losses have no impact on cash flow.

CASH FLOW FROM CONTINUING OPERATIONS AND CURRENT INCOME TAX

Changes to cash flow from continuing operations, when comparing 2004 to prior periods are significantly impacted by increases in the provision for current income tax. The following table has been prepared to disclose the quarterly cash flow from continuing operations and current income tax provisions.

	2004		2003				2002	
($ millions)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Cash Flow from Continuing Operations	**$1,131**	$ 995	$1,217	$ 973	$1,039	$1,191	$ 874	$ 583
Current Income Tax (1)	**$ 203**	$ 232	$ (73)	$ 51	$ (54)	$ 20	$ (107)	$ 16

(1) Amount deducted (added) in determining Cash Flow from Continuing Operations.

Current income tax is discussed in the "Corporate" area under "Results of Operations" in this MD&A.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS

Financial Results *($ millions)*

(Three Months Ended June 30)	2004 Produced Gas	2004 Crude Oil and NGLs	2004 Other	2004 Total	2003 Produced Gas	2003 Crude Oil and NGLs	2003 Other	2003 Total
Revenues, Net of Royalties	$ 1,400	$ 521	$ 54	$ 1,975	$ 1,036	$ 400	$ 56	$ 1,492
Expenses								
Production and mineral taxes	73	23	–	96	38	10	–	48
Transportation and selling	122	32	–	154	83	27	–	110
Operating	125	107	48	280	97	99	46	242
Operating Cash Flow	$ 1,080	$ 359	$ 6	$ 1,445	$ 818	$ 264	$ 10	$ 1,092
Depreciation, depletion and amortization				674				483
Upstream Income				$ 771				$ 609

(Six Months Ended June 30)	2004 Produced Gas	2004 Crude Oil and NGLs	2004 Other	2004 Total	2003 Produced Gas	2003 Crude Oil and NGLs	2003 Other	2003 Total
Revenues, Net of Royalties	$ 2,679	$ 1,000	$ 104	$ 3,783	$ 2,251	$ 802	$ 89	$ 3,142
Expenses								
Production and mineral taxes	119	42	–	161	70	28	–	98
Transportation and selling	232	76	–	308	161	56	–	217
Operating	246	216	95	557	194	184	83	461
Operating Cash Flow	$ 2,082	$ 666	$ 9	$ 2,757	$ 1,826	$ 534	$ 6	$ 2,366
Depreciation, depletion and amortization				1,275				942
Upstream Income				$ 1,482				$ 1,424

Revenue Variances for 2004 Compared to 2003 *($ millions)* (1)

	Three Months Ended June 30				Six Months Ended June 30			
	2003 Revenues, Net of Royalties	Price (2)	Volume	2004 Revenues, Net of Royalties	2003 Revenues, Net of Royalties	Price (2)	Volume	2004 Revenues, Net of Royalties
Produced Gas								
Canada	$ 803	$ 53	$ 125	$ 981	$ 1,728	$ 70	$ 119	$ 1,917
United States	230	45	131	406	517	13	206	736
U.K. North Sea	3	1	9	13	6	4	16	26
Total Produced Gas	$ 1,036	$ 99	$ 265	$ 1,400	$ 2,251	$ 87	$ 341	$ 2,679
Crude Oil and NGLs								
Canada	$ 281	$ (12)	$ 16	$ 285	$ 543	$ (7)	$ 34	$ 570
United States	23	7	7	37	47	7	11	65
Ecuador	75	(5)	77	147	162	(45)	156	273
U.K. North Sea	21	2	29	52	50	(4)	46	92
Total Crude Oil and NGLs	$ 400	$ (8)	$ 129	$ 521	$ 802	$ (49)	$ 247	$ 1,000

(1) Includes continuing operations only.

(2) Includes realized commodity hedging impacts.

Quarterly Sales Volumes

(After Royalties)	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3
Produced Gas *(MMcf per day)*								
Canada								
Production	**2,177**	2,000	2,008	1,914	1,899	1,922	1,943	1,959
Inventory withdrawal / (injection)	**–**	–	–	–	–	120	117	(51)
Canada Sales	**2,177**	2,000	2,008	1,914	1,899	2,042	2,060	1,908
United States	**824**	684	654	604	558	534	516	423
United Kingdom	**36**	28	20	7	12	13	8	9
	3,037	2,712	2,682	2,525	2,469	2,589	2,584	2,340
Oil and Natural Gas Liquids *(bbls per day)* (1)								
Canada	**157,935**	156,640	164,859	163,179	149,292	148,147	148,196	142,856
United States	**12,752**	9,237	9,612	9,691	10,376	8,148	10,162	6,146
Ecuador								
Production	**78,376**	76,320	72,731	54,582	36,754	39,893	34,856	37,447
Transferred to OCP Pipeline (2)	**–**	–	–	(4,919)	(2,039)	(5,941)	–	–
Over / (under) lifting	**(73)**	4,662	4,621	(9,856)	2,506	(2,679)	1,044	2,316
Ecuador Sales	**78,303**	80,982	77,352	39,807	37,221	31,273	35,900	39,763
United Kingdom	**20,728**	18,088	15,067	5,813	9,019	10,610	7,786	9,538
	269,718	264,947	266,890	218,490	205,908	198,178	202,044	198,303
Total *(BOE per day)* (3)	**775,885**	716,947	713,890	639,323	617,408	629,678	632,711	588,303

(1) NGLs include Condensate.

(2) Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

(3) Natural gas converted to BOE at 6 Mcf = 1 BOE.

Year-to-Date Sales Volumes for the Six Months Ended June 30

	Three Months Ended June 30			Six Months Ended June 30		
(After Royalties)	**2004**	**2004 vs 2003**	2003	**2004**	**2004 vs 2003**	2003
Produced Gas *(MMcf per day)*						
Canada						
Production	**2,177**	**15%**	1,899	**2,089**	**9%**	1,910
Inventory withdrawal / (injection)	**–**	**–**	–	**–**	**–**	60
Canada Sales	**2,177**	**15%**	1,899	**2,089**	**6%**	1,970
United States	**824**	**48%**	558	**754**	**38%**	546
United Kingdom	**36**	**200%**	12	**32**	**167%**	12
	3,037	**23%**	2,469	**2,875**	**14%**	2,528
Oil and Natural Gas Liquids *(bbls per day)* (1)						
Canada	**157,935**	**6%**	149,292	**157,288**	**6%**	148,723
United States	**12,752**	**23%**	10,376	**10,995**	**19%**	9,268
Ecuador						
Production	**78,376**	**113%**	36,754	**77,348**	**102%**	38,314
Transferred to OCP Pipeline (2)	**–**	**–**	(2,039)	**–**	**–**	(3,979)
Over / (under) lifting	**(73)**	**–**	2,506	**2,295**	**–**	(72)
Ecuador Sales	**78,303**	**110%**	37,221	**79,643**	**132%**	34,263
United Kingdom	**20,728**	**130%**	9,019	**19,408**	**98%**	9,810
	269,718	**31%**	205,908	**267,334**	**32%**	202,064
Total *(BOE per day)* (3)	**775,885**	**26%**	617,408	**746,501**	**20%**	623,397

(1) NGLs include Condensate.

(2) Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

(3) Natural gas converted to BOE at 6 Mcf = 1 BOE.

Consolidated Upstream Results

Overall results reflect a 26 percent increase in sales volumes of 158,477 BOE per day during the second quarter compared with the same period in 2003. On a year-to-date basis, 2004 volumes are higher by 20 percent or 123,104 BOE per day compared to 2003. Natural gas sales volume increases in the second quarter and six months ended June 30, 2004, were primarily the result of resource play drilling successes in the U.S. Rockies, northeast British Columbia and southern Alberta in Canada and the TBI acquisition. Increases in liquids volumes were primarily the result of the commencement of shipments on the OCP Pipeline in September 2003 which allowed access to market for EnCana's full production capability, increased interests acquired in the Scott and Telford fields in the U.K., higher volumes in the U.S. Rockies and Canada offset partially by the Petrovera disposition. The higher liquids volumes in North America resulted from drilling successes in the U.S. Rockies, continued oil development at Foster Creek, Weyburn and Suffield as well as the TBI acquisition.

The increase in sales volumes accounts for approximately 81 percent of the change in revenues, net of royalties in the second quarter of 2004 and approximately 94 percent for the first six months of 2004. Impacts to revenues, net of royalties resulting from price changes includes realized commodity hedging losses of $234 million, or $3.31 per BOE, in the second quarter 2004 compared to $87 million, or $1.55 per BOE in the three month period ended June 30, 2003. For the six months ended June 30, 2004, realized commodity hedge losses were $383 million, or $2.82 per BOE, compared to $225 million or $1.99 per BOE for the same period in 2003.

Increases in production and mineral taxes, transportation and selling costs as well as operating expenses in 2004 for the quarter and year-to-date compared to the same periods in 2003 were primarily driven by the higher volumes discussed previously. Contributing to the overall increases in expenses was the year-to-date change in the average U.S./Canadian dollar exchange rate and its impact on Canadian dollar denominated expenses. Production and mineral taxes in the U.S. Rockies in the quarter and for the six months ended June 30, 2004 compared to the same periods in 2003 were higher as a result of an increase in rates as a result of higher production volumes in Colorado. Natural gas transportation and selling costs include $21 million for the buyout of third party physical gas contracts in place since prior to the time of the merger with Alberta Energy Company Ltd ("AEC") in April 2002. Operating expenses in the second quarter in 2004 averaged $3.29 per BOE compared to $3.46 per BOE in 2003 primarily as a result of the Petrovera disposition, lower per unit expenses in Ecuador as a result of the proportion of fixed costs distributed over increased volumes offset partially by the impact of the higher U.S./Canadian dollar exchange rate on Canadian operations. For the six months ended June 30, 2004, operating expenses were $3.40 per BOE compared to $3.35 per BOE for the same period in 2003.

Depreciation, depletion and amortization ("DD&A") expense increased by $191 million in the second quarter of 2004 and $333 million year-to-date June 30, 2004, compared to the same periods in 2003 primarily as a result of increased sales volumes and the impact of the higher value of the Canadian dollar compared to the U.S. dollar applied to Canadian dollar denominated DD&A expense. The second quarter 2004 results also include a $14 million expense for impairment of an Upstream international exploration prospect in Ghana. On a BOE basis, excluding Other activities, DD&A rates were $9.28 per BOE for the second quarter of 2004 compared to $8.58 per BOE in the same period of 2003. DD&A rates were $9.21 per BOE for the first six months of 2004 compared to $8.33 per BOE in the same period of 2003. Increased DD&A rates in the second quarter and on a year-to-date basis in 2004 were primarily the result of the increase in the average U.S./Canadian dollar exchange rate and the acquisition of TBI.

Per Unit Results – Produced Gas *($ per thousand cubic feet)*

(Three Months Ended June 30)	Canada 2004	Canada 2004 vs 2003	Canada 2003	United States 2004	United States 2004 vs 2003	United States 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price, net of royalties (1)	**$ 5.20**	**6%**	$ 4.92	**$ 5.72**	**21%**	$ 4.74	**$ 3.73**	**59%**	$ 2.34
Expenses									
Production and mineral taxes	**0.07**	**–13%**	0.08	**0.80**	**74%**	0.46	**–**	**–**	–
Transportation and selling	**0.35**	**0%**	0.35	**0.34**	**–6%**	0.36	**2.57**	**21%**	2.13
Operating	**0.49**	**4%**	0.47	**0.37**	**19%**	0.31	**–**	**–**	–
Netback	**$ 4.29**		$ 4.02	**$ 4.21**		$ 3.61	**$ 1.16**		$ 0.21
Gas Sales Volumes *(MMcf per day)*	**2,177**	**15%**	1,899	**824**	**48%**	558	**36**	**200%**	12

(1) Excludes realized commodity and currency hedge activities.

(Six Months Ended June 30)	Canada 2004	Canada 2004 vs 2003	Canada 2003	United States 2004	United States 2004 vs 2003	United States 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price, net of royalties (1)	**$ 5.21**	**0%**	$ 5.23	**$ 5.57**	**11%**	$ 5.02	**$ 4.18**	**49%**	$ 2.80
Expenses									
Production and mineral taxes	**0.07**	**40%**	0.05	**0.67**	**31%**	0.51	**–**	**–**	–
Transportation and selling	**0.39**	**15%**	0.34	**0.36**	**6%**	0.34	**2.24**	**11%**	2.01
Operating	**0.52**	**8%**	0.48	**0.36**	**38%**	0.26	**–**	**–**	–
Netback	**$ 4.23**		$ 4.36	**$ 4.18**		$ 3.91	**$ 1.94**		$ 0.79
Gas Sales Volumes *(MMcf per day)*	**2,089**	**6%**	1,970	**754**	**38%**	546	**32**	**167%**	12

(1) Excludes realized commodity and currency hedge activities.

Average realized prices, net of royalties, excluding the impact of financial hedges, for natural gas produced in Canada have remained relatively flat when comparing the first six months of 2004 to the same period in 2003. Lower price differentials between North American producing basins and NYMEX tended to offset a lower NYMEX price in the first six months of 2004 compared to 2003, realizing a higher price for the Company's U.S. production. Realized currency and commodity hedging losses on natural gas was approximately $69 million, or $0.25 per Mcf in the second quarter of 2004 compared to a loss of approximately $56 million, or $0.25 per Mcf in the second quarter 2003. On a year-to-date basis to June 30, realized currency and commodity hedging losses on natural gas was approximately $89 million, or $0.17 per million cubic feet in 2004 compared to a loss of approximately $115 million, or $0.25 per million cubic feet in 2003.

Per unit production and mineral taxes in the U.S. Rockies in the quarter and for the six months ended June 30, 2004 compared to the same periods in 2003 were higher as a result of an increase in the rates as a result of the increased production volumes in Colorado.

Canadian produced natural gas per unit transportation and selling costs were flat for the second quarter of 2004 compared to the same period in 2003 but $0.05 higher on a year-to-date basis primarily as a result of higher average distances to sales markets from production facilities and the increased U.S./Canadian exchange rate. The U.K. increases in transportation and selling expense in the second quarter and year-to-date 2004 compared to the same periods in 2003 reflect a change in the cost sharing arrangements for the Scottish Area Gas Evacuation ("SAGE") pipeline as a result of the 2004 acquisition of additional interests in the Scott and Telford fields.

Increases in per unit operating expenses for Canadian produced gas for the second quarter and year-to-date results in 2004 compared to the same periods in 2003 are mainly due to the increased U.S./Canadian dollar exchange rate. Increase in per unit operating expenses in the U.S. produced gas for the second quarter and year-to-date 2004 compared to the same periods in 2003 were primarily due to higher operating costs from the TBI and North Texas property acquisitions and non-recurring charges related to the prior year.

Per Unit Results – Crude Oil and NGLs

Crude Oil *($ per barrel)*

(Three Months Ended June 30)	Canada 2004	Canada 2004 vs 2003	Canada 2003	Ecuador 2004	Ecuador 2004 vs 2003	Ecuador 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price, net of royalties (1)	**$ 26.85**	**17%**	$ 22.95	**$ 27.78**	**25%**	$ 22.31	**$ 34.68**	**28%**	$ 27.17
Expenses									
Production and mineral taxes	**0.35**	**–29%**	0.49	**1.84**	**66%**	1.11	**–**	**–**	–
Transportation and selling	**1.17**	**–23%**	1.51	**1.92**	**–20%**	2.41	**1.85**	**–1%**	1.86
Operating	**4.83**	**–21%**	6.13	**4.14**	**–26%**	5.63	**7.84**	**67%**	4.69
Netback	**$ 20.50**		$ 14.82	**$ 19.88**		$ 13.16	**$ 24.99**		$ 20.62
Crude Oil Sales Volumes *(bbls per day)*	**144,347**	**7%**	134,552	**78,303**	**110%**	37,221	**18,698**	**123%**	8,402

(1) Excludes realized commodity and currency hedge activities.

NGLs (1) *($ per barrel)*

(Three Months Ended June 30)	Canada 2004	Canada 2004 vs 2003	Canada 2003	United States 2004	United States 2004 vs 2003	United States 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price, net of royalties (1)	**$ 28.48**	**35%**	$ 21.02	**$ 32.93**	**34%**	$ 24.64	**$ 23.19**	**50%**	$ 15.45
Expenses									
Production and mineral taxes	**–**	**–**	–	**3.93**	**225%**	1.21	**–**	**–**	–
Transportation and selling	**0.35**	**–**	–	**–**	**–**	–	**1.41**	**–63%**	3.83
Netback	**$ 28.13**		$ 21.02	**$ 29.00**		$ 23.43	**$ 21.78**		$ 11.62
NGLs Sales Volumes *(bbls per day)*	**13,588**	**–8%**	14,740	**12,752**	**25%**	10,194	**2,030**	**229%**	617

(1) NGLs results includes Condensate.

Average realized crude oil prices, excluding the impact of financial hedges, in the second quarter of 2004 reflect the increase in the benchmark West Texas Intermediate ("WTI") and Dated Brent oil prices, offset partially by the increased applicable differentials compared to the same period of 2003. Higher benchmark WTI crude oil prices of 32 percent in the quarter compared to the same period in 2003 were partially offset by increased crude oil price differentials and a higher proportionate share of heavier blend oils in the product mix. Realized currency and commodity hedging losses on crude oil was approximately $164 million, or $6.69 per barrel in the second quarter of 2004 compared to a loss of approximately $30 million, or $1.61 per barrel in second quarter 2003.

Canadian per unit production and mineral taxes decreased in the quarter primarily as a result of increased weighting from properties that are not subject to production and mineral taxes and as a result of the Petrovera disposition. Per unit production and mineral taxes in Ecuador increased $0.73 per barrel in the second quarter of 2004 over the second quarter of 2003 due to higher realized prices on the Tarapoa block volumes. The Company is required to pay the Ecuadorian government a percentage of revenue from this block based on realized prices over a base price.

Second quarter per unit crude oil transportation and selling costs in Canada were lower by $0.34 per barrel over the comparable period in 2003. This is primarily due to a change in the method of allocating transportation between the Upstream and Midstream & Marketing segments which was revised during the third quarter of 2003. Per unit transportation and selling costs in Ecuador for the second quarter decreased as a result of lower net realized costs of operations of the OCP Pipeline.

Second quarter Canadian per unit operating expenses for crude oil decreased as a result of the sale of Petrovera and lower per unit fixed costs due to increased volumes offset partially by the increased U.S./Canadian exchange rate. In Ecuador, a significant portion of operating expenses are fixed, resulting in lower per unit operating expenses as sales volumes increased in the second quarter of 2004 compared to the same period in 2003. The increase in the U.K.'s second quarter 2004 operating expenses is primarily related to increased payroll taxes, additional fuel and maintenance expenses and non-recurring charges related to prior years.

Crude Oil *($ per barrel)*

(Six Months Ended June 30)	Canada 2004	Canada 2004 vs 2003	Canada 2003	Ecuador 2004	Ecuador 2004 vs 2003	Ecuador 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price, net of royalties (1)	**$ 25.79**	**7%**	$ 24.13	**$ 25.77**	**–2%**	$ 26.19	**$ 33.03**	**14%**	$ 28.99
Expenses									
Production and mineral taxes	**0.36**	**–22%**	0.46	**1.60**	**–37%**	2.54	**–**	**–**	–
Transportation and selling	**1.34**	**–17%**	1.61	**2.28**	**–4%**	2.38	**1.89**	**–13%**	2.17
Operating	**5.22**	**–12%**	5.92	**4.09**	**–24%**	5.38	**6.00**	**60%**	3.76
Netback	**$ 18.87**		$ 16.14	**$ 17.80**		$ 15.89	**$ 25.14**		$ 23.06
Crude Oil Sales Volumes *(bbls per day)*	**143,508**	**7%**	133,709	**79,643**	**132%**	34,263	**17,391**	**95%**	8,933

(1) Excludes realized commodity and currency hedge activities.

NGLs (1) *($ per barrel)*

(Six Months Ended June 30)	Canada 2004	Canada 2004 vs 2003	Canada 2003	United States 2004	United States 2004 vs 2003	United States 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price, net of royalties	**$ 27.87**	**15%**	$ 24.21	**$ 32.86**	**18%**	$ 27.91	**$ 22.74**	**7%**	$ 21.19
Expenses									
Production and mineral taxes	**–**	**–**	–	**3.58**	**163%**	1.36	**–**	**–**	–
Transportation and selling	**0.35**	**–**	–	**–**	**–**	–	**1.58**	**16%**	1.36
Netback	**$ 27.52**		$ 24.21	**$ 29.28**		$ 26.55	**$ 21.16**		$ 19.83
NGLs Sales Volumes *(bbls per day)*	**13,780**	**–8%**	15,014	**10,995**	**21%**	9,074	**2,017**	**130%**	877

(1) NGLs results includes Condensate.

Average realized crude oil prices, excluding the impact of financial hedges, for year-to-date 2004 reflects the increase in WTI and Dated Brent, offset partially by the increased applicable differentials, compared to the same period of 2003. Higher benchmark WTI crude oil prices of 17 percent on a year-to-date basis compared to the same period in 2003 were partially offset by increased crude oil price differentials and a higher proportionate share of heavier blend oils in the product mix. On a year-to-date basis to June 30, realized currency and commodity hedging losses on crude oil was approximately $294 million, or $6.04 per barrel in 2004 compared to a loss of approximately $110 million, or $3.00 per barrel in 2003.

Canadian per unit production and mineral taxes decreased on a year-to-date basis as a result of increased weighting from properties that are not subject to production and mineral taxes and the Petrovera disposition. Per unit production and mineral taxes in Ecuador decreased $0.94 per barrel on a year-to-date basis in 2004. This was due to the year-to-date average price for the Tarapoa block volumes being comparatively lower than the same period in 2003. The Company is required to pay the Ecuadorian government a percentage of revenue from this block based on realized prices over a base price.

Six month per unit crude oil transportation and selling costs in Canada were lower by $0.27 per barrel over the comparable period in 2003. This is primarily due to a change in the method of allocating transportation between the Upstream and Midstream & Marketing segments which was revised during the third quarter of 2003.

Year-to-date Canadian per unit operating expenses for crude oil decreased as a result of the sale of Petrovera and lower per unit fixed costs due to increased volumes offset partially by the increased U.S./Canadian exchange rate. In Ecuador, a significant portion of operating expenses are fixed, resulting in lower per unit operating expenses as sales volumes increased year-to-date 2004 compared to the same period in 2003. The increase in the U.K.'s year-to-date 2004 operating expenses is primarily related to increased payroll taxes, additional fuel and maintenance expenses and non-recurring charges related to prior years.

MIDSTREAM & MARKETING OPERATIONS

Financial Results *($ millions)*

(Three Months Ended June 30)	Midstream 2004	Midstream 2004 vs 2003	Midstream 2003	Marketing 2004	Marketing 2004 vs 2003	Marketing 2003	Total 2004	Total 2004 vs 2003	Total 2003
Revenues	$ 172	14%	$ 151	$ 726	6%	$ 688	$ 898	7%	$ 839
Expenses									
Transportation and selling	–	–	–	8	–47%	15	8	–47%	15
Operating	56	8%	52	13	–58%	31	69	–17%	83
Purchased product	118	10%	107	704	6%	662	822	7%	769
Depreciation, depletion and amortization	43	514%	7	2	–	–	45	543%	7
	$ (45)	200%	$ (15)	$ (1)	–95%	$ (20)	$ (46)	31%	$ (35)

(Six Months Ended June 30)	Midstream 2004	Midstream 2004 vs 2003	Midstream 2003	Marketing 2004	Marketing 2004 vs 2003	Marketing 2003	Total 2004	Total 2004 vs 2003	Total 2003
Revenues	$ 723	54%	$ 469	$ 1,594	9%	$ 1,463	$ 2,317	20%	$ 1,932
Expenses									
Transportation and selling	–	–	–	16	–52%	33	16	–52%	33
Operating	127	–3%	131	20	–57%	46	147	–17%	177
Purchased product	567	82%	311	1,542	10%	1,403	2,109	23%	1,714
Depreciation, depletion and amortization	50	355%	11	2	100%	1	52	333%	12
	$ (21)	–231%	$ 16	$ 14	–170%	$ (20)	$ (7)	75%	$ (4)

Revenues and purchased product expense in Midstream & Marketing operations increased in the second quarter and on a six-month basis compared to the same periods in 2003 due primarily to significant increases in the volume of optimization activity in the Midstream gas storage business unit associated with increased capacity from new and expanded facilities. This activity involves the purchase and sale of third party gas to capture storage value relating to storage capacity not leased to third party customers. Decreases in transportation and selling costs in the second quarter and year-to-date to June 30, 2004 compared to the same periods in 2003 is primarily due to the reallocation of all natural gas downstream transportation costs to the Upstream segment. Operating expenses in the second quarter of 2003 included a $20 million settlement with the U.S. commodity Futures Trading Commission as described in the "Contractual Obligations and Contingencies" section of this MD&A which represents the primary reason for the decrease when comparing quarterly and year-to-date results between 2003 and 2004.

The increase in second quarter 2004 and six month DD&A is primarily due to a write down in the value of the Company's equity investment interest in the Trasandino Pipeline in Argentina and Chile of approximately $35 million.

CORPORATE

Corporate Items *($ millions)*

	Three Months Ended June 30 2004	Three Months 2004 vs 2003	Three Months 2003	Six Months Ended June 30 2004	Six Months 2004 vs 2003	Six Months 2003
Revenues, Net of Royalties	$ (155)	–	$ 1	$ (532)	–	$ 1
Expenses						
Operating	(3)	–	–	(5)	–	–
Depreciation, depletion and amortization	14	27%	11	30	67%	18
Administration	44	2%	43	93	16%	80
Interest, net	96	43%	67	175	34%	131
Accretion of asset retirement obligation	5	–	5	12	20%	10
Foreign exchange loss (gain)	21	–110%	(206)	79	–119%	(416)
Stock-based compensation	4	–33%	6	9	50%	6
Gain on disposition	(1)	–	–	(35)	–	–
Income tax (recovery) expense	140	–190%	(156)	45	–67%	137

Corporate revenues, net of royalties in the second quarter of 2004 include unrealized mark-to-market losses of approximately $156 million related to commodity contracts. On a year-to-date basis, revenues, net of royalties include mark-to-market losses on commodity contracts of approximately $535 million. Other mark-to-market gains or losses on derivative financial instruments are recorded in the applicable account to which the contract relates. Corporate operating expense in the quarter and year-to-date 2004 includes mark-to-market gains of $2 million and $5 million respectively related to power consumption contracts.

Depreciation, depletion and amortization include provisions for corporate assets such as computer equipment, office furniture and leasehold improvements. The increase in expense for the quarter and on a year-to-date basis is the result of higher capital spending in prior periods on corporate capital items and the impact of the change in the U.S./Canadian dollar exchange rate.

The administrative expenses for the second quarter of 2004 compared to the same period in 2003 are relatively unchanged. The year-to-date results reflect the effect of the change in the U.S./Canadian dollar exchange rate and increased long-term compensation expenses. Administrative costs were lower by $0.15 per BOE, at $0.62 per BOE, for the second quarter of 2004 ($0.68 per BOE year-to-date) compared with $0.77 per BOE for the second quarter in 2003 ($0.71 per BOE year-to-date). Lower per unit administrative expenses are primarily as a result of the increase in sales volumes.

The higher net interest expense resulted primarily from the higher average outstanding debt level as a result of the TBI acquisition in the second quarter and on a year-to-date basis for 2004 versus the same periods in 2003 and the impact of the change in the U.S./Canadian dollar exchange rate.

The majority of the foreign exchange loss of $21 million in the second quarter resulted from the change in the U.S./Canadian dollar period-end exchange rate between March 31, 2004 and June 30, 2004 applied to U.S. dollar denominated debt issued in Canada. The unrealized foreign exchange loss, before tax, on U.S. dollar denominated debt issued in Canada for the three months ended June 30, 2004 was $32 million compared to an unrealized before tax gain of $211 million for the second quarter of 2003. For the six months ended June 30, the unrealized foreign exchange loss, before tax, on U.S. dollar denominated debt issued in Canada for 2004 was $71 million compared to an unrealized before tax gain of $389 million for 2003. Under Canadian GAAP, the Company is required to translate long-term debt issued in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings.

The effective tax rate for the second quarter of 2004 was 36 percent compared to a recovery of 24 percent for the same period in 2003 as disclosed in Note 8 to the Interim Consolidated Financial Statements. On a year-to-date basis to June 30, the effective tax rate for 2004 was 8 percent compared to 9 percent for 2003. EnCana's effective tax rate in any particular reporting period is a function of the relationship between the amount of net earnings before income taxes for the period and the magnitude of the items representing "permanent differences" that are excluded from the calculation of earnings for the period that will be subject to tax. There are a variety of items of this type, including:

- The non-taxable half of Canadian capital gains (losses);
- Adjustments for the impact of legislative changes which have prospective impact on future income tax obligations;
- The effects of asset dispositions where the tax values of the assets sold differ from the accounting value; and
- Items such as resource allowance, non-deductible crown payments and some marked to market adjustments where the treatment is different for income tax and accounting purposes.

Given the nature and scale of EnCana's activities, it is difficult to forecast the magnitude and timing of these types of items.

After reflecting the adjustments to future income taxes referred to above, the relative level of increased net earnings before income tax and giving effect to the recently announced disposition of certain of the Company's oil and gas interests, the Company is reducing the range of its expected 2004 effective tax rate to between 24 and 29 percent. These effective rates may be impacted by the effect of future unrealized foreign exchange gains or losses in respect of the revaluation of debt denominated in U.S. dollars and additional oil and gas asset dispositions.

Current income tax expense for the second quarter of 2004 was $203 million compared to a recovery of $54 million for the same period in 2003. Current taxes were expected to increase significantly in 2004 when compared to the prior year as the effects of the merger with AEC were reflected in the Company's tax position for 2003.

The operations of the Company are complex and related tax interpretations, regulations and legislation in the various jurisdictions that the Company and its subsidiaries operate in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

CAPITAL EXPENDITURES

Quarterly Capital Investment *($ millions)*

	2004		2003				2002	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Upstream								
Canada	**$ 670**	$ 1,014	$ 841	$ 897	$ 496	$ 703	$ 446	$ 266
United States	**316**	210	215	279	197	139	136	163
Ecuador	**56**	54	93	65	34	73	62	60
United Kingdom	**115**	93	67	19	10	16	17	26
Other Countries	**19**	15	15	15	31	17	75	17
Total Upstream	**$ 1,176**	$ 1,386	$ 1,231	$ 1,275	$ 768	$ 948	$ 736	$ 532
Midstream & Marketing	**16**	9	69	58	75	21	22	14
Corporate	**9**	9	19	7	19	12	24	12
Core Capital Expenditures	**$ 1,201**	$ 1,404	$ 1,319	$ 1,340	$ 862	$ 981	$ 782	$ 558
Acquisition of Tom Brown, Inc. (1)	**2,335**	–	–	–	–	–	–	–
Acquisitions (2)	**6**	387	358	96	220	146	118	361
Dispositions	**(106)**	(566)	(296)	–	(12)	(7)	(181)	(85)
Net Capital Expenditures (3)	**$ 3,436**	$ 1,225	$ 1,381	$ 1,436	$ 1,070	$ 1,120	$ 719	$ 834

(1) Excludes approximately $406 million of TBI debt.

(2) Represents Corporate acquisitions and property acquisitions.

(3) Excludes discontinued operations.

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	2004	2004 vs 2003	2003	2004	2004 vs 2003	2003
Upstream						
Canada	**$ 670**	**35%**	$ 496	**$ 1,684**	**40%**	$ 1,199
United States	**316**	**60%**	197	**526**	**57%**	336
Ecuador	**56**	**65%**	34	**110**	**3%**	107
United Kingdom	**115**	**1,050%**	10	**208**	**700%**	26
Other Countries	**19**	**–39%**	31	**34**	**–29%**	48
Total Upstream	**$ 1,176**	**53%**	$ 768	**$ 2,562**	**49%**	$ 1,716
Midstream & Marketing	**16**	**–79%**	75	**25**	**–74%**	96
Corporate	**9**	**–53%**	19	**18**	**–42%**	31
Core Capital Expenditures	**$ 1,201**	**39%**	$ 862	**$ 2,605**	**41%**	$ 1,843
Acquisition of Tom Brown, Inc. (1)	**2,335**	**–**	–	**2,335**	**–**	–
Acquisitions (2)	**6**	**-97%**	220	**393**	**7%**	366
Dispositions	**(106)**	**783%**	(12)	**(672)**	**3,437%**	(19)
Net Capital Expenditures (3)	**$ 3,436**	**221%**	$ 1,070	**$ 4,661**	**113%**	$ 2,190

(1) Excludes approximately $406 million of TBI debt.

(2) Represents Corporate acquisitions and property acquisitions.

(3) Excludes discontinued operations.

The Company's net capital expenditures increased $2,366 million for the second quarter of 2004 and $2,471 million for the six months ended June 30, 2004 compared to the same periods respectively in 2003 as a result of the TBI acquisition, higher levels of operating activity in Upstream, and the impact of the higher U.S./Canadian dollar exchange rate. The Company's capital investment was funded by cash flow in excess of amounts paid for purchases under the Normal Course Issuer Bid, proceeds received on dispositions of non-core assets as well as debt.

Upstream Capital Expenditures

Increases in Upstream capital expenditures in the second quarter and on a year-to-date basis in 2004 reflect increased drilling and development activities and the impact of the increased average U.S./Canadian dollar exchange rate on Canadian dollar denominated expenditures. Capital spending was primarily focused on North American resource play properties with spending in Canada directed mostly at natural gas and oil exploration and development of properties on the Suffield and Palliser Blocks in southeast Alberta, as well as Greater Sierra and Cutbank Ridge in northeast British Columbia and Pelican Lake in northeast Alberta. The majority of capital expenditures in the U.S. were directed towards drilling in the Mamm Creek and Jonah areas. Capital expenditures in the U.K. primarily reflect the development of the Buzzard field. The Company drilled 2,684 net wells year-to-date June 30, 2004 compared to 2,285 net wells in the same period for 2003.

Midstream & Marketing Capital Expenditures

Capital expenditures in Midstream & Marketing relate primarily to improvements to midstream facilities and various development initiatives. Expenditure levels were significantly higher in 2003 due to the expansion of the gas storage business and amounts related to the buyout of equipment operating leases.

Corporate Capital Expenditures

Corporate capital expenditures relate primarily to spending on business information systems, leasehold improvements and furniture and office equipment.

Acquisitions and Divestitures

In May 2004, the Company completed a cash tender offer to purchase all of the outstanding Common Shares of TBI for total consideration of approximately $2.7 billion including the acquired debt of approximately $0.4 billion as discussed earlier in this MD&A under "Continuing Alignment of North American Assets with EnCana's Resource Play Strategy".

In February 2004, an EnCana U.K. subsidiary completed the purchase of an additional 13.5 percent and 20.2 percent interest in the Scott and Telford fields, respectively, for net cash consideration of approximately $113 million. As a result of this acquisition and the initial ownership interest held, the EnCana U.K. subsidiary now holds a 41 percent interest in the Scott field and a 54.3 percent interest in the Telford field.

In February 2004, the Company sold its 53.3 percent partnership interest in Petrovera Resources ("Petrovera") for net cash consideration of approximately $288 million including working capital adjustments. To facilitate this transaction, the Company purchased the 46.7 percent interest of its partner and then sold the 100 percent interest in Petrovera for approximately $541 million including working capital adjustments. There was no gain or loss recorded on this sale.

During the second quarter of 2004, the Company disposed of various non-core properties in Canada for proceeds of approximately $106 million.

GOODWILL

At June 30, 2004, the Company had $2,298 million in goodwill (March 31, 2004 – $1,884 million) recorded on its Consolidated Balance Sheet. The majority of goodwill was as a result of the merger with AEC in 2002. The increase in goodwill during the second quarter was primarily attributable to the purchase of TBI, as disclosed in Note 3 to the Interim Consolidated Financial Statements, offset partially by the change in the period-end rates to convert Canadian dollars to U.S. dollars.

LIQUIDITY AND CAPITAL RESOURCES

EnCana's cash flow from continuing operations was $1,131 million for the three months ended June 30, 2004, up $92 million compared to the same period last year and on a year-to-date basis was $2,126 million for the period ended June 30, 2004, down $104 million compared to the same six month period in 2003. The increase in cash flows in the quarter and decrease on a year-to-date basis were primarily due to the provision for current tax and increase in the U.S./Canadian dollar exchange rate offset by increased revenues from the growth in sales volumes. The provision for current tax in the second quarter was $203 million compared to a recovery of $54 million in the same period in 2003. On a year-to-date basis, the current income tax provision was $435 million in 2004 compared to a recovery of $34 million in 2003.

EnCana's net debt adjusted for working capital and including the debt acquired as a result of the acquisition of TBI, was $9,282 million as at June 30, 2004 compared with $5,931 million at December 31, 2003. Working capital was a deficit of $700 million at June 30, 2004 and included unrealized losses on mark-to-market accounting on derivatives of $531 million, a current tax payable of $408 million offset partially by assets held for resale of $278 million. This compares to a working capital surplus of $157 million as at December 31, 2003. Cash flow together with proceeds from dispositions was used for the purchase of shares under the Company's Normal Course Issuer Bid, capital expenditures and the purchase of TBI. As a result of these activities, long-term debt plus the current portion of long-term debt increased $2,940 million in the second quarter compared to the 2003 year-end. The Company expects net debt to decrease prior to the 2004 year-end as a result of various non-core asset dispositions planned for the third and fourth quarters of this year as well as increased anticipated cash flows as a result of the TBI acquisition. Total projected proceeds of between $1.5 and $2.0 billion dollars are expected for the full year.

Net debt to capitalization was 43 percent (including announced pro forma disposition proceeds of approximately $660 million) as of June 30, 2004, up from 34 percent at December 31, 2003, primarily as a result of the acquisition of TBI. Management calculates this ratio for internal purposes to steward the Company's overall debt position as a measure of a Company's financial strength.

Following the announcement of the TBI acquisition, the credit rating agencies adjusted EnCana's long-term credit ratings. On July 14, 2004, Moody's lowered EnCana's rating to Baa2 (Stable). Standard & Poor's modified the Company's A- rating with a "Credit Watch with negative implications" and has not completed their subsequent review. Dominion Bond Rating Service has confirmed EnCana's A(low) rating with a trend change from "Stable to Negative". The agencies noted that the debt financed acquisition of TBI put EnCana's credit profile under strain relative to the pre-acquisition ratings levels. The agencies are expected to continue to examine the Company's operating and financial performance as well as its progress on the asset disposition program as they monitor EnCana's credit profile.

As a result of the acquisition, TBI and a subsidiary made a consent tender offer for $225 million of their 7.25 percent Senior Subordinated Notes. A total of 98.9 percent of the notes were tendered for a total cost of approximately $258 million.

In March 2004, an indirect wholly owned subsidiary, EnCana Holdings Finance Corp. ("EHFC"), filed a shelf prospectus whereby it may issue from time to time up to $2 billion of debt securities. Debt securities issued under this shelf prospectus will be unconditionally guaranteed by EnCana Corporation. On May 10, 2004 EHFC completed a $1.0 billion unsecured public debt offering in the U.S. The notes, which are due in 2014, bear a coupon of 5.80 percent. The net proceeds of the offering were used to fund a portion of the acquisition of TBI.

On July 7, 2004 the Company announced its intention to redeem on August 9, 2004 all of its 8.50 percent Unsecured Junior Subordinated Debentures due September 30, 2048 which have an aggregate principal amount of C$200 million. The redemption amount will be the principal amount plus accrued and unpaid interest.

As at June 30, 2004, the Company had available unused committed bank credit facilities in the amount of $1,121 million.

In October 2003, EnCana received approval from the Toronto Stock Exchange to continue to purchase, for cancellation, Common Shares under a Normal Course Issuer Bid (the "Bid"). Under the Bid, EnCana is entitled to purchase for cancellation up to 23.2 million of its Common Shares over a 12-month period ending October 21, 2004. In the second quarter of 2004, EnCana purchased for cancellation approximately 300,000 of its shares at an average price of C$55.61 per share under the Bid. On a year-to-date basis, EnCana purchased for cancellation approximately 5.5 million of its shares at an average price of C$55.37 per share under the Bid. As of June 30, 2004, and including purchases made under the Bid from October through December, 2003, the Company had purchased for cancellation approximately 9.1 million Common Shares at an average price of C$51.56 per share.

BUSINESS ENVIRONMENT

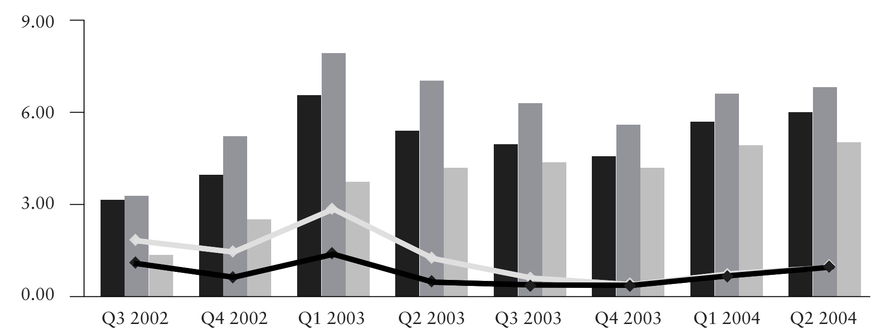
NATURAL GAS

Natural Gas Price Benchmarks

(average for the period)	Three Months Ended June 30 2004	2004 vs 2003	2003	Six Months Ended June 30 2004	2004 vs 2003	2003	Year Ended 2003
AECO Price *(C$/Mcf)*	**$ 6.80**	**–3%**	$ 7.00	**$ 6.71**	**–10%**	$ 7.46	$ 6.70
NYMEX Price *($/MMBtu)*	**5.99**	**11%**	5.41	**5.84**	**–3%**	6.00	5.39
Rockies (Opal) Price *($/MMBtu)*	**5.04**	**21%**	4.17	**4.99**	**26%**	3.96	4.12
AECO/NYMEX Basis Differential *($/MMBtu)*	**0.96**	**104%**	0.47	**0.83**	**–11%**	0.93	0.65
Rockies/NYMEX Basis *($/MMBtu)*	**0.95**	**–23%**	1.24	**0.85**	**–59%**	2.05	1.27

Concerns that North American natural gas supply will not be able to meet increasing demands and the influence of high crude oil prices have continued to result in historically high average NYMEX gas prices. Lower AECO average gas prices in the second quarter and on a year-to-date basis in 2004, compared to the corresponding periods in 2003, can be attributed to lower NYMEX prices in the first quarter and wider differentials from the NYMEX in the second quarter. The increased AECO/NYMEX basis differential in the second quarter of 2004 compared to the second quarter of 2003 can be attributed to increased transportation differentials for the marginal sales volumes transported from Alberta to Eastern Canada.

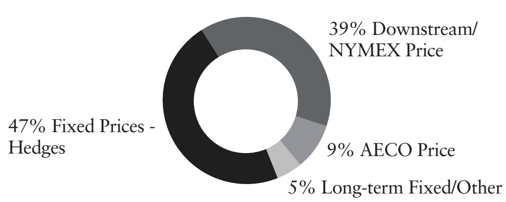
NATURAL GAS BENCHMARKS



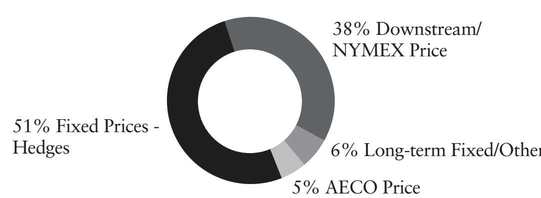
	Q3 2002	Q4 2002	Q1 2003	Q2 2003	Q3 2003	Q4 2003	Q1 2004	Q2 2004
NYMEX Price *($/MMBtu)*	3.18	3.98	6.59	5.41	4.97	4.58	5.69	5.99
AECO Price *(C$/Mcf)*	3.25	5.25	7.92	7.00	6.29	5.59	6.60	6.80
Rockies (Opal) Price *($/MMBtu)*	1.35	2.53	3.74	4.17	4.37	4.19	4.94	5.04
AECO/NYMEX Basis Differential *($/MMBtu)*	1.09	0.63	1.38	0.47	0.38	0.37	0.69	0.96
Rockies/NYMEX Basis *($/MMBtu)*	1.83	1.45	2.85	1.24	0.60	0.39	0.75	0.95

PERCENTAGE OF NATURAL GAS VOLUMES BENCHMARK PRICE EXPOSURES
(Annual approximate percentage)

2003



2004 Including Tom Brown



CRUDE OIL

Crude Oil Price Benchmarks

(average for the period)	Three Months Ended June 30 2004	2004 vs 2003	2003	Six Months Ended June 30 2004	2004 vs 2003	2003	Year Ended 2003
WTI *($/bbl)*	**38.28**	**32%**	28.91	**36.78**	**17%**	31.32	30.99
Dated Brent *($/bbl)*	**35.32**	**36%**	26.03	**33.66**	**17%**	28.74	28.84
WTI/Bow River Differential *($/bbl)*	**11.02**	**68%**	6.55	**10.03**	**42%**	7.07	8.01
WTI/OCP NAPO Differential (Ecuador) *($/bbl)* (1)	**12.17**	**–**	–	**11.91**	**–**	–	8.06
WTI/Oriente Differential (Ecuador) *($/bbl)*	**7.80**	**23%**	6.32	**7.79**	**37%**	5.69	5.59

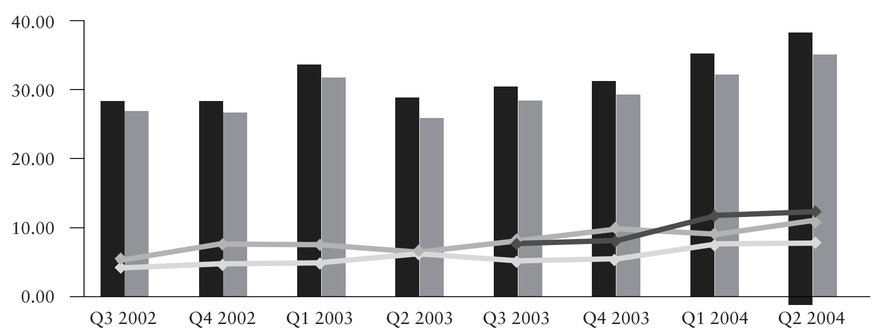
(1) The WTI/OCP NAPO Differential was posted as of September 2003.

The benchmark WTI crude oil price continued to be strong in the second quarter of 2004 compared to the second quarter of 2003 due to strong Asian demand, uncertainty over supply/demand imbalances, the intermittent disruption of Iraqi oil production and OPEC's production management initiatives. The year-to-date WTI crude oil price was significantly higher than the first six months of 2003 primarily as a result of the increase in Asian demand and the increased uncertainty of a stable oil supply from the Middle East.

The Canadian WTI/Bow River heavy oil differential widened in the second quarter of 2004 compared to the second quarter of 2003 primarily due to the higher price for WTI, as well as wider U.S. Gulf Coast light to heavy product differentials. As a percentage of WTI, Bow River's average sales price for the second quarter of 2004 was 71 percent of WTI as compared to 77 percent in the second quarter of 2003. On a year-to-date basis, Canadian WTI/Bow River heavy oil differential was higher primarily as a result of the increase in WTI.

The Company currently transports nearly all of its Ecuadorian production through the OCP Pipeline as NAPO blend. NAPO blend is a heavier crude than the SOTE Oriente blend, previously the predominant crude oil from Ecuador, resulting in a wider differential to WTI. The second quarter and year-to-date 2004 increases in the Oriente differential compared to the same periods in 2003 is primarily related to the increase in the WTI price as well as wider U.S. Gulf Coast light to heavy product differentials.

CRUDE OIL
BENCHMARKS



	Q3 2002	Q4 2002	Q1 2003	Q2 2003	Q3 2003	Q4 2003	Q1 2004	Q2 2004
WTI *($/bbl)*	28.25	28.23	33.80	28.91	30.21	31.16	35.25	38.28
Dated Brent *($/bbl)*	26.95	26.78	31.52	26.03	28.41	29.41	31.95	35.32
WTI/OCP NAPO Differential (Ecuador) *($/bbl)*					7.75	8.17	11.65	12.17
WTI/Oriente Differential (Ecuador) *($/bbl)*	4.35	4.92	5.06	6.32	5.34	5.63	7.70	7.80
WTI/Bow River Differential *($/bbl)*	5.38	7.66	7.58	6.55	8.12	9.77	9.03	11.02

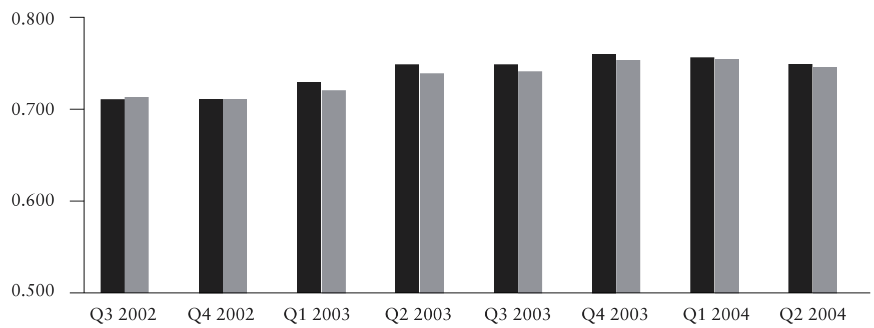
U.S./CANADIAN DOLLAR EXCHANGE RATES

Foreign Exchange Benchmarks

(average for the period)	Three Months Ended June 30 2004	2004 vs 2003	2003	Six Months Ended June 30 2004	2004 vs 2003	2003	Year Ended 2003
U.S./Canadian Dollar Period-End Exchange Rate	**0.746**	**1%**	0.738	**0.746**	**1%**	0.738	0.774
U.S./Canadian Dollar Average Exchange Rate	**0.736**	**3%**	0.715	**0.747**	**9%**	0.689	0.716

The second quarter 2004 over second quarter 2003 average U.S./Canadian dollar exchange rate increase was primarily the result of the economic slowdown in the U.S., continuing differences between Canadian and U.S. interest rates and the U.S. current account deficit. The $0.02 reduction in the second quarter period-end exchange rate compared to the period ended March 31, 2004 resulted in an unrealized loss on the U.S. denominated debt issued in Canada of approximately $32 million ($25 million after-tax) in the quarter. For the first six months of 2004 the average U.S./Canadian dollar exchange rate was higher than the comparable period in 2003 by 9 percent or approximately $0.06. As a result of the increase in the period-end exchange rate at June 30, 2004 compared to the year-end rate at December 31, 2003, the unrealized loss before tax on the U.S. denominated debt issued in Canada was approximately $71 million ($57 million after-tax).

US$/CDN$
EXCHANGE RATE



	Q3 2002	Q4 2002	Q1 2003	Q2 2003	Q3 2003	Q4 2003	Q1 2004	Q2 2004
■ U.S./Canadian Dollar Period-End Exchange Rate	0.631	0.633	0.681	0.738	0.741	0.774	0.763	0.746
■ U.S./Canadian Dollar Average Exchange Rate	0.640	0.637	0.662	0.715	0.725	0.760	0.759	0.736

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. As at June 30, 2004 there were 461.0 million Common Shares outstanding compared to 479.9 million Common Shares outstanding at June 30, 2003 and 460.6 million Common Shares outstanding as at December 31, 2003. There were no preferred shares outstanding as at June 30, 2004 or June 30, 2003.

Employees and directors have been granted options to purchase Common Shares under various plans. During the second quarter of 2004, approximately 1.5 million Common Shares were issued (year-to-date approximately 5.9 million Common Shares) under the terms of these plans. These plans and outstanding balances are disclosed in Note 11 to the Interim Consolidated Financial Statements.

As discussed previously in the Liquidity and Capital Resources section of this MD&A, the Company has repurchased for cancellation approximately 300,000 Common Shares at an average price of C$55.61 during the second quarter and 5.5 million Common Shares at an average price of C$55.37 in the first six months of 2004 under a Normal Course Issuer Bid that was approved by the Toronto Stock Exchange in October, 2003.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements. In addition, the Company has made commitments related to the risk mitigation program and has incurred additional commitments as a result of the TBI acquisition. See Note 14 of the Interim Consolidated Financial Statements for the financial transactions and the Risk Management section of this MD&A for the physical contracts. The TBI acquisition increased fixed long-term debt by approximately $960 million. Transportation and other operating commitments as a result of the TBI acquisition were not material.

Included in the long-term debt commitments, the Company had $3,940 million outstanding as at June 30, 2004 related to Banker's Acceptances, Commercial Paper and LIBOR loans that are supported by revolving credit facilities and term loan borrowings. Approximately $1,740 million, of this amount, is related to the bridge credit facility to finance a portion of the TBI acquisition which is to be repaid by 25 percent by February 2005, a further 50 percent by August 2005 and the final 25 percent by May 2006. With respect to the balance of the outstanding revolving credit facilities and term loan borrowings of approximately $2,200 million, the Company intends and expects that it will have the ability to extend the term on an ongoing basis. Further details regarding the Company's long-term debt are described in Note 9 to the Interim Consolidated Financial Statements.

As at June 30, 2004, EnCana had entered into long-term, fixed price, physical contracts with a current delivery of approximately 46 MMcf per day with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 175 billion cubic feet at a weighted average price of $3.41 per Mcf. At June 30, 2004, these transactions had an unrealized loss of $133 million.

LEGAL PROCEEDINGS RELATED TO DISCONTINUED MERCHANT ENERGY OPERATIONS

In July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD's now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the merger with AEC in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. A motion by the Company and WD to dismiss the Gallo complaint on the basis that the Federal Energy Regulatory Commission had exclusive jurisdiction regarding this matter was not granted. Most of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and all of the New York lawsuits were consolidated in New York District Court by the plaintiff's application. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws. As is customary, none of the other actions specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

ACCOUNTING POLICIES AND ESTIMATES

CHANGES IN ACCOUNTING PRINCIPLES AND PRACTICES

Hedging Relationships

On January 1, 2004, the Company adopted the amendments made to the accounting standard for Hedging Relationships. Derivative instruments outstanding at January 1, 2004, that did not qualify as a hedge or were not designated as a hedge, were recorded using the mark-to-market accounting method whereby their fair value was recorded on the Consolidated Balance Sheet. The impact on the Company's Consolidated Financial Statements at January 1, 2004 was an increase in assets of $145 million, an increase in liabilities of $380 million and a net deferred loss of $235 million. These amounts are taken into net earnings as the contracts expire. At June 30, 2004, approximately $191 million of these net losses were recognized. The timing of recognition of the remaining net losses of $44 million ($31 million after-tax) is described in Note 2 of the Interim Consolidated Financial Statements.

Changes in the fair value from March 31, 2004 to June 30, 2004 for these contracts, as well as all other outstanding hedge contracts, were marked-to-market and a $155 million loss ($104 million after-tax) was recognized in net earnings for the three months ended June 30, 2004. All unrealized losses on derivative instruments as at June 30, 2004 are disclosed in Note 14 of the Interim Consolidated Financial Statements.

RISK MANAGEMENT

EnCana's results are impacted by external market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit, operational and safety and environmental risks. The Company partially mitigates its exposure to market risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors.

COMMODITY PRICES

As a means of mitigating exposure to commodity price volatility, the Company has entered into various financial instrument agreements as disclosed in Note 14 of the Interim Consolidated Financial Statements and physical contracts as detailed in the natural gas section of this MD&A.

Derivative financial instruments are used by the Company to help manage its exposure to market risks related to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of market price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are typically entered into with major financial institutions, integrated energy companies or commodities trading institutions. Realized gains or losses from these derivative financial instruments are recognized in oil and gas revenues at the time the related production occurs. On January 1, 2004, the Company adopted AcG-13 of the CICA and uses the mark-to-market accounting method as described earlier in this MD&A under Hedging Relationships. Under the mark-to-market accounting method, unrealized gains or losses resulting from differences between the contracted commodity price and the period-end forward commodity price curve are also recognized in revenues.

NATURAL GAS

The Company has entered into swaps which fix the AECO and NYMEX prices and collars which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, the Company has entered into financial and physical contracts to fix the AECO and Rockies price differential which is based on the NYMEX price.

The financial contracts are disclosed in Note 14 of the Interim Consolidated Financial Statements. The physical contracts are as follows:

	Notional Volume *(MMcf/d)*	Term	Price *(US$ per Mcf)*	Unrecognized Gain/(Loss) *($ millions)*
Fixed Price Contracts				
Sales Contract				
NYMEX Collars	50	2004	2.46 – 4.90	(13)
NYMEX Collars	50	2005	2.46 – 4.90	(25)
NYMEX Collars	46	2006 – 2007	2.46 – 4.90	(29)
Basis Contracts				
Sales Contract				
Fixed NYMEX to Rockies Basis	410	2004	(0.493)	27
Fixed NYMEX to San Juan Basis	50	2004	(0.637)	1
Fixed NYMEX to Ventura Basis	7	2004	(0.133)	–
Fixed NYMEX to Rockies Basis	393	2005	(0.471)	38
Fixed NYMEX to San Juan Basis	50	2005	(0.637)	1
Fixed NYMEX to Ventura Basis	23	2005	(0.245)	–
Fixed NYMEX to Rockies Basis	207	2006 – 2007	(0.491)	29
Fixed NYMEX to San Juan Basis	42	2006	(0.637)	–
				29
Gas Marketing Physical Positions				16
				$ 45

CRUDE OIL

The Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, costless collars and 3-way put spreads. The instruments are disclosed in Note 14 of the Interim Consolidated Financial Statements. As part of the crude oil marketing activities, the Company partially mitigated its exposure to the risk around crude oil inventory and third party margins through the use of futures, options and collars.

GAS STORAGE OPTIMIZATION

As part of its gas storage optimization program, the Company has entered into financial instruments and physical contracts at various locations and terms over the next 10 months to manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used include futures, fixed for floating swaps and basis swaps.

KYOTO PROTOCOL

The risks associated with the Kyoto Accord and similar initiatives in the U.S.A. remain unchanged as discussed in the 2003 year-end MD&A.

ALBERTA ENERGY AND UTILITIES BOARD ("AEUB") RULING

The Company's production volumes, primarily from the Primrose Block in northeast Alberta, were affected by an AEUB decision, in September 2003, to shut-in natural gas production that put at risk the recovery of bitumen resources in the area. The impact of this decision caused the Company's second quarter natural gas production in the region to be lower by approximately 10 MMcf per day when compared to the second quarter of 2003. On July 1, 2004 a second order has been issued from the AEUB to shut-in an additional 8 MMcf per day. The future impact of these announced decisions is not expected to be material.

OUTLOOK

EnCana plans to focus on exploitation of its resource plays to grow natural gas and crude oil production in North America as well as continue to develop conventional crude oil production in Ecuador, U.K. and North America. Longer-term growth is expected to be augmented by development of projects in the Gulf of Mexico, Canadian East Coast, and U.K. central North Sea. The Company also plans to continue its focused, high upside North American and international exploration programs.

Capital Outlook

($ millions)	**2004 Full-Year Guidance** [3]	Six Months Ended June 30, 2004	2005 Full-Year Guidance [3]
Upstream	**$4,550 – $4,850**	$2,562	$4,750 – $5,250
Midstream & Marketing and Corporate	**150**	43	
Core Capital Expenditures	**$4,700 – $5,000**	$2,605	
Acquisition of Tom Brown, Inc. [2]	**2,700**	2,335	
Divestitures, net of Acquisitions [1]	**(2,000) – (1,500)**	(279)	
Net Capital Investment	**$5,400 – $6,200**	$4,661	

(1) Represents Corporate acquisitions and property acquisitions.

(2) Six month actuals excludes acquired debt of approximately $406 million.

(3) Guidance released June 15, 2004.

The Company expects its 2004 core capital investment program to be between $4,700 million and $5,000 million and funded from cash flow and proceeds from divestitures of non-core assets. Net capital investment guidance was amended in the second quarter of 2004 to include additional opportunities identified in the Company's development program of its resource play assets in the U.S. and Canada as well as opportunities resulting from the recent acquisition of TBI. Additional asset sales are expected to occur in the Canadian Western Sedimentary basin in the last half of 2004.

Volume Outlook

	2004 Full-Year Guidance [2]	Six Months Ended June 30, 2004	2005 Full-Year Guidance [2]
Produced Gas Sales *(MMcf per day)*			
Canada	**2,100 – 2,140**	2,089	
United States	**700 – 725**	754	
United Kingdom	**30**	32	
Tom Brown, Inc.	**165 – 175**		
Additional divestments	**(45) – (20)**		
Total Produced Gas Sales	**2,950 – 3,050**	2,875	3,400 – 3,550
Crude Oil and NGLs *(bbls per day)*			
Canada	**150,000 – 154,000**	157,288	
United States	**9,000 – 10,000**	10,995	
Ecuador	**72,000 – 76,000**	79,643	
United Kingdom	**16,000 – 18,000**	19,408	
Tom Brown, Inc.	**4,000**		
Additional divestments	**(16,000) – (7,000)**		
Total Crude Oil and NGLs	**235,000 – 255,000**	267,334	250,000 – 270,000
Total *(BOE per day)* [1]	**725,000 – 765,000**	746,501	810,000 – 860,000

(1) Natural gas converted to BOE at 6 Mcf = 1 BOE.

(2) Guidance released June 15, 2004. TBI and additional divestments have been annualized.

Sales volume guidance for 2004 was increased in the second quarter and represents an approximate 15 percent growth over 2003 full year sales volumes (based on the midpoint of guidance). Included in the increased guidance is a 12 percent organic growth rate from the Company's inventory of resource plays and international assets. The guidance range for sales volumes was increased in June 2004 to reflect the strong operating performance from the Company's resource play assets in North America year-to-date. The annualized impact of the TBI acquisition less planned dispositions is expected to be approximately neutral to total sales volumes.

COMMODITY PRICES

The influence of high crude oil prices, limited natural gas production growth in the oil and gas industry, increasing demand and uncertainty surrounding the ability of producers to maintain storage inventory levels have resulted in continued higher historical average natural gas prices. The outlook for 2004 and beyond will be principally impacted by weather, timing of new production and economic activity.

Worldwide uncertainty in crude oil markets caused by production disruptions in the Middle East and Africa, increased demand from Asian countries, North American crude and product inventory levels, potential supply uncertainty in Russia as well as concerns about OPEC's ability to meet growing worldwide demand. The outlook for the longer term is principally dependent on the ability of producers to grow crude and stabilize natural gas supply, the timing of new production, the weather and economic activity.

OPERATING AND ADMINISTRATIVE EXPENSES

Total operating costs for 2004 are expected to range between $3.30 and $3.50 per BOE with administrative expense between $0.60 and $0.70 per BOE. Depreciation, depletion and amortization rates for the Company's Upstream segment are expected to range between $8.60 and $9.10 per BOE for 2004.

CURRENT INCOME TAXES

EnCana has previously provided guidance for the 2004 provision for current income taxes in the range of $675 million to $820 million. At the date hereof, and based on First Call consensus commodity pricing and production and capital expenditures estimates based on the mid-point of public guidance, EnCana expects the 2004 provision for current income taxes will be within, but at the high end of, the guidance range. Current income tax for 2004 is expected to be approximately 15 percent to 20 percent of the Company's pre-tax cash flow.

Sensitivity of 2005 Net Earnings and Cash Flow (Including Hedges) (1)

($ millions)	Net Earnings	Cash Flow
$0.25 per million British thermal units increase in the NYMEX gas price	175	230
$1.00 per barrel increase in the WTI oil price	35	45
$0.01 decrease in the U.S./Canadian dollar exchange rate	(25)	20

(1) Hedge position as at April 30, 2004.

Sensitivity of 2005 Net Earnings and Cash Flow (Excluding Hedges)

($ millions)	Net **Earnings**	Cash Flow
$0.25 per million British thermal units increase in the NYMEX gas price	195	250
$1.00 per barrel increase in the WTI oil price	50	65
$0.01 decrease in the U.S./Canadian dollar exchange rate	(25)	20

July 26, 2004

For the period ended June 30, 2004

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

(US$ millions, except per share amounts)		June 30 Three Months Ended 2004	Three Months Ended 2003	Six Months Ended 2004	Six Months Ended 2003
REVENUES, NET OF ROYALTIES	(Notes 5)				
Upstream		$ **1,975**	$ 1,492	$ **3,783**	$ 3,142
Midstream & Marketing		**898**	839	**2,317**	1,932
Corporate		**(155)**	1	**(532)**	1
		2,718	2,332	**5,568**	5,075
EXPENSES	(Note 5)				
Production and mineral taxes		**96**	48	**161**	98
Transportation and selling		**162**	125	**324**	250
Operating		**346**	325	**699**	638
Purchased product		**822**	769	**2,109**	1,714
Depreciation, depletion and amortization		**733**	501	**1,357**	972
Administrative		**44**	43	**93**	80
Interest, net		**96**	67	**175**	131
Accretion of asset retirement obligation	(Note 10)	**5**	5	**12**	10
Foreign exchange loss (gain)	(Note 7)	**21**	(206)	**79**	(416)
Stock-based compensation		**4**	6	**9**	6
Gain on dispositions	(Note 4)	**(1)**	–	**(35)**	–
		2,328	1,683	**4,983**	3,483
NET EARNINGS BEFORE INCOME TAX		**390**	649	**585**	1,592
Income tax expense (recovery)	(Note 8)	**140**	(156)	**45**	137
NET EARNINGS FROM CONTINUING OPERATIONS		**250**	805	**540**	1,455
NET EARNINGS FROM DISCONTINUED OPERATIONS	(Note 6)	**–**	2	**–**	189
NET EARNINGS		$ **250**	$ 807	$ **540**	$ 1,644
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	(Note 13)				
Basic		$ **0.54**	$ 1.67	$ **1.17**	$ 3.03
Diluted		$ **0.54**	$ 1.66	$ **1.16**	$ 3.01
NET EARNINGS PER COMMON SHARE	(Note 13)				
Basic		$ **0.54**	$ 1.68	$ **1.17**	$ 3.42
Diluted		$ **0.54**	$ 1.67	$ **1.16**	$ 3.40

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

(US$ millions)		Six Months Ended June 30, 2004	2003
RETAINED EARNINGS, BEGINNING OF YEAR			
As previously reported		$ **5,276**	$ 3,457
Retroactive adjustment for changes in accounting policies		**–**	66
As restated		**5,276**	3,523
Net Earnings		**540**	1,644
Dividends on Common Shares		**(92)**	(68)
Charges for Normal Course Issuer Bid	(Note 11)	**(126)**	(6)
RETAINED EARNINGS, END OF PERIOD		$ **5,598**	$ 5,093

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

For the period ended June 30, 2004

(US$ millions)		As at June 30, 2004	As at December 31, 2003
ASSETS			
Current Assets			
Cash and cash equivalents		$ 202	$ 148
Accounts receivable and accrued revenues		1,953	1,367
Risk management	*(Note 14)*	64	–
Inventories		545	573
Assets held for sale	*(Note 3)*	278	–
		3,042	2,088
Property, Plant and Equipment, net	*(Note 5)*	22,963	19,545
Investments and Other Assets		582	566
Risk Management	*(Note 14)*	91	–
Goodwill		2,298	1,911
	(Note 5)	$ 28,976	$ 24,110
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,004	$ 1,579
Risk management	*(Note 14)*	597	–
Income tax payable		408	65
Current portion of long-term debt	*(Note 9)*	733	287
		3,742	1,931
Long-Term Debt	*(Note 9)*	8,582	6,088
Other Liabilities		101	21
Risk Management	*(Note 14)*	122	–
Asset Retirement Obligation	*(Note 10)*	467	430
Future Income Taxes		4,557	4,362
		17,571	12,832
Shareholders' Equity			
Share capital	*(Note 11)*	5,382	5,305
Share options, net		25	55
Paid in surplus		37	18
Retained earnings		5,598	5,276
Foreign currency translation adjustment		363	624
		11,405	11,278
		$ 28,976	$ 24,110

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

For the period ended June 30, 2004

(US$ millions)		Three Months Ended June 30 2004	Three Months Ended June 30 2003	Six Months Ended June 30 2004	Six Months Ended June 30 2003
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 250**	$ 805	**$ 540**	$ 1,455
Depreciation, depletion and amortization		**733**	501	**1,357**	972
Future income taxes	*(Note 8)*	**(63)**	(102)	**(390)**	171
Unrealized loss on risk management	*(Note 14)*	**155**	–	**531**	–
Unrealized foreign exchange loss (gain)	*(Note 7)*	**32**	(211)	**71**	(389)
Accretion of asset retirement obligation	*(Note 10)*	**5**	5	**12**	10
Gain on dispositions	*(Note 4)*	**(1)**	–	**(35)**	–
Other		**20**	41	**40**	11
Cash flow from continuing operations		**1,131**	1,039	**2,126**	2,230
Cash flow from discontinued operations		**–**	(32)	**–**	(2)
Cash flow		**1,131**	1,007	**2,126**	2,228
Net change in other assets and liabilities		**(41)**	17	**(46)**	29
Net change in non-cash working capital from continuing operations		**(294)**	10	**173**	41
Net change in non-cash working capital from discontinued operations		**–**	46	**–**	57
		796	1,080	**2,253**	2,355
INVESTING ACTIVITIES					
Business combination with Tom Brown, Inc.	*(Note 3)*	**(2,335)**	–	**(2,335)**	–
Capital expenditures	*(Note 5)*	**(1,207)**	(1,082)	**(2,745)**	(2,093)
Proceeds on disposal of property, plant and equipment		**106**	12	**131**	19
Dispositions (acquisitions)	*(Note 4)*	**–**	–	**288**	(116)
Equity investments	*(Note 4)*	**–**	(88)	**44**	(133)
Net change in investments and other		**(20)**	(4)	**(22)**	(27)
Net change in non-cash working capital from continuing operations		**(131)**	(24)	**(46)**	(158)
Discontinued operations		**–**	(11)	**–**	1,278
		(3,587)	(1,197)	**(4,685)**	(1,230)
FINANCING ACTIVITIES					
Issuance of long-term debt		**3,195**	361	**3,195**	361
Repayment of long-term debt		**(433)**	–	**(536)**	(892)
Issuance of Common Shares	*(Note 11)*	**43**	54	**154**	83
Purchase of Common Shares	*(Note 11)*	**(12)**	(122)	**(230)**	(122)
Dividends on Common Shares		**(46)**	(35)	**(92)**	(68)
Other		**(4)**	(12)	**(5)**	(13)
Discontinued operations		**–**	–	**–**	(282)
		2,743	246	**2,486**	(933)
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**–**	6	**–**	8
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**(48)**	123	**54**	184
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**250**	177	**148**	116
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 202**	$ 300	**$ 202**	$ 300

See accompanying Notes to Consolidated Financial Statements.

For the period ended June 30, 2004

(All amounts in US$ millions unless otherwise specified)

NOTE 1

BASIS OF PRESENTATION

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries (the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration for, and production and marketing of, natural gas, natural gas liquids and crude oil, as well as natural gas storage operations, natural gas liquids processing and power generation operations.

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2003, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2003.

NOTE 2

CHANGE IN ACCOUNTING POLICIES AND PRACTICES

Hedging Relationships

On January 1, 2004, the Company adopted the amendments made to Accounting Guideline 13 ("AcG – 13") "Hedging Relationships", and EIC 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". Derivative instruments that do not qualify as a hedge under AcG – 13, or are not designated as a hedge, are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. The Company has elected not to designate any of its price risk management activities in place at June 30, 2004 as accounting hedges under AcG – 13 and, accordingly, will account for all these non-hedging derivatives using the mark-to-market accounting method. The impact on the Company's Consolidated Financial Statements at January 1, 2004 resulted in the recognition of risk management assets with a fair value of $145 million, risk management liabilities with a fair value of $380 million and a net deferred loss of $235 million which will be recognized into net earnings as the contracts expire. At June 30, 2004, it is estimated that over the following 12 months, $102 million ($72 million, net of tax) will be reclassified into net earnings from net deferred losses.

The following table presents the deferred amounts expected to be recognized in net earnings as unrealized gains/(losses) over the years 2004 to 2008:

	Unrealized Gain/(Loss)
2004	
Quarter 3	$ (51)
Quarter 4	(64)
Total remaining to be recognized in 2004	$ (115)
2005	
Quarter 1	$ –
Quarter 2	13
Quarter 3	9
Quarter 4	9
Total to be recognized in 2005	$ 31
2006	$ 24
2007	15
2008	1
Total to be recognized	$ (44)

At June 30, 2004, the remaining net deferred loss totalled $44 million of which $139 million was recorded in Accounts receivable and accrued revenues, $3 million in Investments and other assets, $37 million in Accounts payable and accrued liabilities and $61 million in Other liabilities.

NOTE 3

BUSINESS COMBINATION WITH TOM BROWN, INC.

In May 2004, the Company completed the tender offer for the Common Shares of Tom Brown, Inc., a Denver based independent energy company for total cash consideration of $2.3 billion.

The business combination has been accounted for using the purchase method with results of operations of Tom Brown, Inc. included in the Consolidated Financial Statements from the date of acquisition.

The calculation of the purchase price and the preliminary allocation to assets and liabilities is shown below. The purchase price and goodwill allocation is preliminary because certain items such as determination of the final tax bases and fair values of the assets and liabilities as of the acquisition date have not been completed.

Calculation of Purchase Price	
Cash paid for Common Shares of Tom Brown, Inc.	$ 2,341
Transaction costs	13
Total purchase price	$ 2,354
Plus: Fair value of liabilities assumed	
Current liabilities	$ 276
Long-term debt	406
Other non-current liabilities	39
Future income taxes	710
Total Purchase Price and Liabilities Assumed	$ 3,785
Fair Value of Assets Acquired	
Current assets (including cash acquired of $19 million)	$ 440
Property, plant, and equipment	2,879
Other non-current assets	9
Goodwill	457
Total Fair Value of Assets Acquired	$ 3,785

Included in current assets as Assets held for sale is $278 million related to the value of certain oil and gas properties located in west Texas and southwestern New Mexico and the assets of Sauer Drilling Company, a subsidiary of Tom Brown, Inc., which the Company has entered into purchase and sale agreements. These transactions are expected to close in the third quarter of 2004.

NOTE 4

DISPOSITIONS (ACQUISITIONS)

In March 2004, the Company sold its investment in a well servicing company for approximately $44 million, recording a gain on sale of $34 million.

On February 18, 2004, the Company sold its 53.3 percent interest in Petrovera Resources (“Petrovera”) for approximately $288 million, including working capital adjustments. In order to facilitate the transaction, EnCana purchased the 46.7 percent interest of its partner for approximately $253 million, including working capital adjustments, and then sold the 100 percent interest in Petrovera for a total of approximately $541 million, including working capital adjustments. There was no gain or loss recorded on this sale.

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. (“Vintage”) for net cash consideration of $116 million. This purchase was accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the date of acquisition.

Other dispositions of discontinued operations are disclosed in Note 6.

NOTE 5

SEGMENTED INFORMATION

The Company has defined its continuing operations into the following segments:

- Upstream includes the Company's exploration for, and development and production of, natural gas, natural gas liquids and crude oil and other related activities. The majority of the Company's Upstream operations are located in Canada, the United States, the United Kingdom and Ecuador. International new venture exploration is mainly focused on opportunities in Africa, South America and the Middle East.
- Midstream & Marketing includes natural gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activities. These marketing activities include the sale and delivery of produced product and the purchasing of third party product primarily for the optimization of midstream assets, as well as the optimization of transportation arrangements not fully utilized for the Company's own production.
- Corporate includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Midstream & Marketing purchases all of the Company's North American Upstream production. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

Operations that have been discontinued are disclosed in Note 6.

Results of Operations *(For the three months ended June 30)*

	Upstream		Midstream & Marketing	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 1,975**	$ 1,492	**$ 898**	$ 839
Expenses				
Production and mineral taxes	**96**	48	**–**	–
Transportation and selling	**154**	110	**8**	15
Operating	**280**	242	**69**	83
Purchased product	**–**	–	**822**	769
Depreciation, depletion and amortization	**674**	483	**45**	7
Segment Income	**$ 771**	$ 609	**$ (46)**	$ (35)

	Corporate		Consolidated	
	2004	2003	**2004**	2003
Revenues, Net of Royalties *	**$ (155)**	$ 1	**$ 2,718**	$ 2,332
Expenses				
Production and mineral taxes	**–**	–	**96**	48
Transportation and selling	**–**	–	**162**	125
Operating	**(3)**	–	**346**	325
Purchased product	**–**	–	**822**	769
Depreciation, depletion and amortization	**14**	11	**733**	501
Segment Income	**$ (166)**	$ (10)	**559**	564
Administrative			**44**	43
Interest, net			**96**	67
Accretion of asset retirement obligation			**5**	5
Foreign exchange loss (gain)			**21**	(206)
Stock-based compensation			**4**	6
Gain on dispositions			**(1)**	–
			169	(85)
Net Earnings Before Income Tax			**390**	649
Income tax expense (recovery)			**140**	(156)
Net Earnings from Continuing Operations			**$ 250**	$ 805

* Corporate revenue primarily reflects unrealized gains or losses recorded on derivative instruments. See also Note 14.

Results of Operations *(For the three months ended June 30)*

UPSTREAM	Canada		United States		Ecuador	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 1,266**	$ 1,084	**$ 443**	$ 253	**$ 147**	$ 75
Expenses						
Production and mineral taxes	**18**	20	**65**	24	**13**	4
Transportation and selling	**84**	80	**45**	19	**14**	8
Operating	**161**	158	**28**	15	**29**	19
Depreciation, depletion and amortization	**435**	365	**117**	67	**69**	31
Segment Income	**$ 568**	$ 461	**$ 188**	$ 128	**$ 22**	$ 13

Transportation and selling in 2004 for the United States includes a one-time payment of $21 million made to terminate a long-term physical delivery contract.

	U.K. North Sea		Other		Total Upstream	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 65**	$ 24	**$ 54**	$ 56	**$ 1,975**	$ 1,492
Expenses						
Production and mineral taxes	**–**	–	**–**	–	**96**	48
Transportation and selling	**11**	3	**–**	–	**154**	110
Operating	**14**	4	**48**	46	**280**	242
Depreciation, depletion and amortization	**34**	19	**19**	1	**674**	483
Segment Income	**$ 6**	$ (2)	**$ (13)**	$ 9	**$ 771**	$ 609

MIDSTREAM & MARKETING	Midstream		Marketing		Total Midstream & Marketing	
	2004	2003	**2004**	2003	**2004**	2003
Revenues	**$ 172**	$ 151	**$ 726**	$ 688	**$ 898**	$ 839
Expenses						
Transportation and selling	**–**	–	**8**	15	**8**	15
Operating	**56**	52	**13**	31	**69**	83
Purchased product	**118**	107	**704**	662	**822**	769
Depreciation, depletion and amortization	**43**	7	**2**	–	**45**	7
Segment Income	**$ (45)**	$ (15)	**$ (1)**	$ (20)	**$ (46)**	$ (35)

Midstream Depreciation, depletion and amortization in 2004 includes a $35 million impairment charge on the Company's interest in Oleoducto Trasandino in Argentina and Chile.

NOTE 5
(continued)

Upstream Geographic and Product Information *(For the three months ended June 30)*

PRODUCED GAS

	Produced Gas							
	Canada		United States		U.K. North Sea		Total	
	2004	2003	**2004**	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 981**	$ 803	**$ 406**	$ 230	**$ 13**	$ 3	**$ 1,400**	$ 1,036
Expenses								
Production and mineral taxes	**13**	14	**60**	24	**–**	–	**73**	38
Transportation and selling	**69**	61	**45**	19	**8**	3	**122**	83
Operating	**97**	82	**28**	15	**–**	–	**125**	97
Operating Cash Flow	**$ 802**	$ 646	**$ 273**	$ 172	**$ 5**	$ –	**$ 1,080**	$ 818

Transportation and selling in 2004 for the United States includes a one-time payment of $21 million made to terminate a long-term physical delivery contract.

OIL & NGLs

	Oil & NGLs					
	Canada		United States		Ecuador	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 285**	$ 281	**$ 37**	$ 23	**$ 147**	$ 75
Expenses						
Production and mineral taxes	**5**	6	**5**	–	**13**	4
Transportation and selling	**15**	19	**–**	–	**14**	8
Operating	**64**	76	**–**	–	**29**	19
Operating Cash Flow	**$ 201**	$ 180	**$ 32**	$ 23	**$ 91**	$ 44

	Oil & NGLs			
	U.K. North Sea		Total	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 52**	$ 21	**$ 521**	$ 400
Expenses				
Production and mineral taxes	**–**	–	**23**	10
Transportation and selling	**3**	–	**32**	27
Operating	**14**	4	**107**	99
Operating Cash Flow	**$ 35**	$ 17	**$ 359**	$ 264

OTHER & TOTAL UPSTREAM

	Other		Total Upstream	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 54**	$ 56	**$ 1,975**	$ 1,492
Expenses				
Production and mineral taxes	**–**	–	**96**	48
Transportation and selling	**–**	–	**154**	110
Operating	**48**	46	**280**	242
Operating Cash Flow	**$ 6**	$ 10	**$ 1,445**	$ 1,092

Results of Operations *(For the six months ended June 30)*

	Upstream		Midstream & Marketing	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 3,783**	$ 3,142	**$ 2,317**	$ 1,932
Expenses				
Production and mineral taxes	**161**	98	**–**	–
Transportation and selling	**308**	217	**16**	33
Operating	**557**	461	**147**	177
Purchased product	**–**	–	**2,109**	1,714
Depreciation, depletion and amortization	**1,275**	942	**52**	12
Segment Income	**$ 1,482**	$ 1,424	**$ (7)**	$ (4)

	Corporate		Consolidated	
	2004	2003	**2004**	2003
Revenues, Net of Royalties *	**$ (532)**	$ 1	**$ 5,568**	$ 5,075
Expenses				
Production and mineral taxes	**–**	–	**161**	98
Transportation and selling	**–**	–	**324**	250
Operating	**(5)**	–	**699**	638
Purchased product	**–**	–	**2,109**	1,714
Depreciation, depletion and amortization	**30**	18	**1,357**	972
Segment Income	**$ (557)**	$ (17)	**918**	1,403
Administrative			**93**	80
Interest, net			**175**	131
Accretion of asset retirement obligation			**12**	10
Foreign exchange loss (gain)			**79**	(416)
Stock-based compensation			**9**	6
Gain on dispositions			**(35)**	–
			333	(189)
Net Earnings Before Income Tax			**585**	1,592
Income tax expense (recovery)			**45**	137
Net Earnings from Continuing Operations			**$ 540**	$ 1,455

* Corporate revenue primarily reflects unrealized gains or losses recorded on derivative instruments. See also Note 14.

NOTE 5
(continued)

Results of Operations *(For the six months ended June 30)*

UPSTREAM	Canada		United States		Ecuador	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 2,487**	$ 2,271	**$ 801**	$ 564	**$ 273**	$ 162
Expenses						
Production and mineral taxes	**38**	29	**99**	53	**24**	16
Transportation and selling	**186**	161	**70**	34	**33**	15
Operating	**335**	312	**48**	25	**59**	34
Depreciation, depletion and amortization	**851**	712	**199**	133	**134**	54
Segment Income	**$ 1,077**	$ 1,057	**$ 385**	$ 319	**$ 23**	$ 43

Transportation and selling in 2004 for the United States includes a one-time payment of $21 million made to terminate a long-term physical delivery contract.

	U.K. North Sea		Other		Total Upstream	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 118**	$ 56	**$ 104**	$ 89	**$ 3,783**	$ 3,142
Expenses						
Production and mineral taxes	**–**	–	**–**	–	**161**	98
Transportation and selling	**19**	7	**–**	–	**308**	217
Operating	**20**	7	**95**	83	**557**	461
Depreciation, depletion and amortization	**67**	41	**24**	2	**1,275**	942
Segment Income	**$ 12**	$ 1	**$ (15)**	$ 4	**$ 1,482**	$ 1,424

MIDSTREAM & MARKETING	Midstream		Marketing		Total Midstream & Marketing	
	2004	2003	**2004**	2003	**2004**	2003
Revenues	**$ 723**	$ 469	**$ 1,594**	$ 1,463	**$ 2,317**	$ 1,932
Expenses						
Transportation and selling	**–**	–	**16**	33	**16**	33
Operating	**127**	131	**20**	46	**147**	177
Purchased product	**567**	311	**1,542**	1,403	**2,109**	1,714
Depreciation, depletion and amortization	**50**	11	**2**	1	**52**	12
Segment Income	**$ (21)**	$ 16	**$ 14**	$ (20)	**$ (7)**	$ (4)

Midstream Depreciation, depletion and amortization in 2004 includes a $35 million impairment charge on the Company's interest in Oleoducto Trasandino in Argentina and Chile.

Upstream Geographic and Product Information *(For the six months ended June 30)*

PRODUCED GAS

	Produced Gas							
	Canada		United States		U.K. North Sea		Total	
	2004	2003	**2004**	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 1,917**	$ 1,728	**$ 736**	$ 517	**$ 26**	$ 6	**$ 2,679**	$ 2,251
Expenses								
Production and mineral taxes	**28**	18	**91**	52	**–**	–	**119**	70
Transportation and selling	**150**	122	**70**	34	**12**	5	**232**	161
Operating	**198**	169	**48**	25	**–**	–	**246**	194
Operating Cash Flow	**$ 1,541**	$ 1,419	**$ 527**	$ 406	**$ 14**	$ 1	**$ 2,082**	$ 1,826

Transportation and selling in 2004 for the United States includes a one-time payment of $21 million made to terminate a long-term physical delivery contract.

OIL & NGLs

	Oil & NGLs					
	Canada		United States		Ecuador	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 570**	$ 543	**$ 65**	$ 47	**$ 273**	$ 162
Expenses						
Production and mineral taxes	**10**	11	**8**	1	**24**	16
Transportation and selling	**36**	39	**–**	–	**33**	15
Operating	**137**	143	**–**	–	**59**	34
Operating Cash Flow	**$ 387**	$ 350	**$ 57**	$ 46	**$ 157**	$ 97

	Oil & NGLs			
	U.K. North Sea		Total	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 92**	$ 50	**$ 1,000**	$ 802
Expenses				
Production and mineral taxes	**–**	–	**42**	28
Transportation and selling	**7**	2	**76**	56
Operating	**20**	7	**216**	184
Operating Cash Flow	**$ 65**	$ 41	**$ 666**	$ 534

OTHER & TOTAL UPSTREAM

	Other		Total Upstream	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 104**	$ 89	**$ 3,783**	$ 3,142
Expenses				
Production and mineral taxes	**–**	–	**161**	98
Transportation and selling	**–**	–	**308**	217
Operating	**95**	83	**557**	461
Operating Cash Flow	**$ 9**	$ 6	**$ 2,757**	$ 2,366

NOTE 5
(continued)

Capital Expenditures

	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
Upstream				
Canada	$ **675**	$ 679	$ **1,703**	$ 1,386
United States	**316**	196	**526**	346
Ecuador	**56**	34	**110**	107
United Kingdom	**116**	10	**329**	26
Other Countries	**19**	31	**34**	48
	1,182	950	**2,702**	1,913
Midstream & Marketing	**16**	113	**25**	149
Corporate	**9**	19	**18**	31
Total	$ **1,207**	$ 1,082	$ **2,745**	$ 2,093

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
	As at		As at	
	June 30, 2004	December 31, 2003	**June 30, 2004**	December 31, 2003
Upstream	$ **21,980**	$ 18,532	$ **26,373**	$ 21,742
Midstream & Marketing	**768**	784	**1,763**	1,879
Corporate	**215**	229	**840**	489
Total	$ **22,963**	$ 19,545	$ **28,976**	$ 24,110

NOTE 6

DISCONTINUED OPERATIONS

On February 28, 2003, the Company completed the sale of its 10 percent working interest in the Syncrude Joint Venture ("Syncrude") to Canadian Oil Sands Limited for net cash consideration of C$1,026 million ($690 million). On July 10, 2003, the Company completed the sale of the remaining 3.75 percent interest in Syncrude and a gross overriding royalty for net cash consideration of C$427 million ($309 million). There was no gain or loss on this sale.

On January 2, 2003 and January 9, 2003, the Company completed the sales of its interests in the Cold Lake Pipeline System and Express Pipeline System for total consideration of approximately C$1.6 billion ($1 billion), including assumption of related long-term debt by the purchaser, and recorded an after-tax gain on sale of C$263 million ($169 million).

As all discontinued operations have either been disposed of or wind up has been completed by December 31, 2003, there are no remaining assets or liabilities on the Consolidated Balance Sheet. The following tables present the effect of the discontinued operations on the Consolidated Statement of Earnings for 2003:

Consolidated Statement of Earnings

For the three months ended June 30, 2003	Syncrude	Midstream – Pipelines	Total
Revenues, Net of Royalties	$ 19	$ –	$ 19
Expenses			
Transportation and selling	1	–	1
Operating	14	–	14
Depreciation, depletion and amortization	1	–	1
Gain on discontinuance	–	–	–
	16	–	16
Net Earnings Before Income Tax	3	–	3
Income tax expense	1	–	1
Net Earnings from Discontinued Operations	$ 2	$ –	$ 2

Consolidated Statement of Earnings

For the six months ended June 30, 2003	Syncrude	Midstream – Pipelines	Total
Revenues, Net of Royalties	$ 79	$ –	$ 79
Expenses			
Transportation and selling	2	–	2
Operating	42	–	42
Depreciation, depletion and amortization	6	–	6
Gain on discontinuance	–	(220)	(220)
	50	(220)	(170)
Net Earnings Before Income Tax	29	220	249
Income tax expense	9	51	60
Net Earnings from Discontinued Operations	$ 20	$ 169	$ 189

NOTE 7

FOREIGN EXCHANGE LOSS (GAIN)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	**2004**	2003
Unrealized Foreign Exchange Loss (Gain) on Translation of U.S. Dollar Debt Issued in Canada	**$ 32**	$ (211)	**$ 71**	$ (389)
Realized Foreign Exchange Loss (Gain)	**(11)**	5	**8**	(27)
	$ 21	$ (206)	**$ 79**	$ (416)

NOTE 8

INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	**2004**	2003
Current				
Canada	**$ 160**	$ (61)	**$ 365**	$ (49)
United States	**7**	–	**15**	–
Ecuador	**35**	5	**54**	13
United Kingdom	**–**	2	**–**	2
Other	**1**	–	**1**	–
Total Current Tax	**203**	(54)	**435**	(34)
Future	**(63)**	260	**(281)**	533
Future Tax Rate Reductions *	**–**	(362)	**(109)**	(362)
Total Future Tax	**(63)**	(102)	**(390)**	171
	$ 140	$ (156)	**$ 45**	$ 137

* On March 31, 2004, the Alberta government substantively enacted the income tax rate reduction previously announced in February 2004.

NOTE 8
(continued)

The following table reconciles income taxes calculated at the Canadian statutory rate with the actual income taxes:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	**2004**	2003
Net Earnings Before Income Tax	**$ 390**	$ 649	**$ 585**	$ 1,592
Canadian Statutory Rate	**39.1%**	41.0%	**39.1%**	41.0%
Expected Income Taxes	**153**	266	**229**	652
Effect on Taxes Resulting from:				
Non-deductible Canadian crown payments	**51**	54	**103**	132
Canadian resource allowance	**(59)**	(45)	**(116)**	(150)
Canadian resource allowance on unrealized risk management losses	**6**	–	**27**	–
Statutory and other rate differences	**(21)**	(13)	**(30)**	(24)
Effect of tax rate changes	**–**	(362)	**(109)**	(362)
Non-taxable capital gains	**7**	(36)	**14**	(70)
Previously unrecognized capital losses	**2**	–	**15**	–
Tax recovery on dispositions	**(23)**	–	**(103)**	–
Large corporations tax	**3**	10	**7**	17
Other	**21**	(30)	**8**	(58)
	$ 140	$ (156)	**$ 45**	$ 137
Effective Tax Rate	**35.9%**	(24.0%)	**7.7%**	8.6%

NOTE 9

LONG-TERM DEBT

	As at June 30, 2004	As at December 31, 2003
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 1,660**	$ 1,425
Unsecured notes and debentures	**1,250**	1,335
Preferred securities	**149**	252
	3,059	3,012
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowing	**2,306**	417
Unsecured notes and debentures	**3,722**	2,713
Preferred securities	**150**	150
	6,178	3,280
Increase in Value of Debt Acquired *	**78**	83
Current Portion of Long-Term Debt	**(733)**	(287)
	$ 8,582	$ 6,088

* Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 27 years.

To fund the acquisition of Tom Brown, Inc., the Company arranged a $3 billion non-revolving term loan facility with a group of the Company's lenders. Currently the facility size has been reduced to $1.8 billion with a drawn amount of $1.7 billion. Amounts borrowed under the facility are to be repaid as follows: 25 percent within nine months of initial drawdown, a further 50 percent within 15 months of the initial drawdown and the final 25 percent within 24 months of initial drawdown.

NOTE 10

ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties:

	As at June 30, 2004	As at December 31, 2003
Asset Retirement Obligation, Beginning of Year	**$ 430**	$ 309
Liabilities Incurred	**55**	64
Liabilities Settled	**(6)**	(23)
Liabilities Disposed	**(13)**	–
Accretion Expense	**12**	19
Other	**(11)**	61
Asset Retirement Obligation, End of Period	**$ 467**	$ 430

NOTE 11

SHARE CAPITAL

	June 30, 2004		December 31, 2003	
(millions)	**Number**	**Amount**	Number	Amount
Common Shares Outstanding, Beginning of Year	**460.6**	**$ 5,305**	478.9	$ 5,511
Shares Issued under Option Plans	**5.9**	**154**	5.5	114
Shares Repurchased	**(5.5)**	**(77)**	(23.8)	(320)
Common Shares Outstanding, End of Period	**461.0**	**$ 5,382**	460.6	$ 5,305

To June 30, 2004, the Company purchased, for cancellation, 5,490,000 Common Shares for total consideration of approximately C$304 million ($230 million). Of the amount paid, C$101 million ($77 million) was charged to Share capital, C$36 million ($27 million) was charged to Paid in surplus and C$167 million ($126 million) was charged to Retained earnings.

The Company has stock-based compensation plans that allow employees and directors to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous successor and/or related company replacement plans expire ten years from the date the options were granted.

The following tables summarize the information about options to purchase Common Shares at June 30, 2004:

	Stock Options *(millions)*	**Weighted Average Exercise Price** *(C$)*
Outstanding, Beginning of Year	28.8	43.13
Exercised	(5.9)	34.71
Forfeited	(0.5)	47.06
Outstanding, End of Period	22.4	45.20
Exercisable, End of Period	14.1	43.15

NOTE 11
(continued)

Range of Exercise Price *(C$)*	Outstanding Options: Number of Options Outstanding *(millions)*	Outstanding Options: Weighted Average Remaining Contractual Life *(years)*	Outstanding Options: Weighted Average Exercise Price *(C$)*	Exercisable Options: Number of Options Outstanding *(millions)*	Exercisable Options: Weighted Average Exercise Price *(C$)*
13.50 to 19.99	0.5	0.8	18.63	0.5	18.63
20.00 to 24.99	0.9	1.2	22.50	0.9	22.50
25.00 to 29.99	0.8	1.4	26.23	0.8	26.23
30.00 to 43.99	0.7	1.9	39.45	0.7	38.92
44.00 to 53.00	19.5	3.3	47.96	11.2	47.38
	22.4	2.6	45.20	14.1	43.15

The Company has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair-value method. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share for the three months ended June 30, 2004 would have been $241 million; $0.52 per common share – basic; $0.52 per common share – diluted (2003 – $798 million; $1.66 per common share – basic; $1.65 per common share – diluted). Pro forma Net Earnings and Net Earnings per Common Share for the six months ended June 30, 2004 would have been $522 million; $1.13 per common share – basic; $1.12 per common share – diluted (2003 – $1,627 million; $3.39 per common share – basic; $3.36 per common share – diluted).

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

	June 30, 2003
Weighted Average Fair Value of Options Granted *(C$)*	$ 12.18
Risk Free Interest Rate	3.96%
Expected Lives *(years)*	3.00
Expected Volatility	0.33
Annual Dividend per Share *(C$)*	$ $0.40

NOTE 12

COMPENSATION PLANS

The tables below outline certain information related to the Company's compensation plans at June 30, 2004. Additional information is contained in Note 16 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2003.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
Current Service Cost	**$ 1**	$ 2	**$ 3**	$ 3
Interest Cost	**3**	3	**6**	6
Expected Return on Plan Assets	**(3)**	(3)	**(6)**	(5)
Amortization of Net Actuarial Loss	**2**	1	**2**	2
Amortization of Transitional Obligation	**(1)**	(1)	**(1)**	(1)
Amortization of Past Service Cost	**1**	1	**1**	1
Expense for Defined Contribution Plan	**4**	3	**7**	6
Net Benefit Plan Expense	**$ 7**	$ 6	**$ 12**	$ 12

At June 30, 2004, $9 million has been contributed to the pension plans and the Company expects to make additional contributions of $8 million in 2004.

B) Share Appreciation Rights ("SAR's")

The following table summarizes the information about SAR's at June 30, 2004:

	Outstanding SAR's	Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	1,175,070	35.87
Exercised	(434,342)	35.48
Forfeited	(11,040)	29.25
Outstanding, End of Period	729,688	36.18
Exercisable, End of Period	729,688	36.18
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	753,417	28.98
Exercised	(249,358)	29.26
Forfeited	(1,472)	24.08
Outstanding, End of Period	502,587	28.86
Exercisable, End of Period	502,587	28.86

The following table summarizes the information about Tandem SAR's at June 30, 2004:

	Outstanding Tandem SAR's	Weighted Average Exercise Price *(C$)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	–	–
Granted	897,850	54.44
Forfeited	(7,400)	53.01
Outstanding, End of Period	890,450	54.45
Exercisable, End of Period	–	–

C) Deferred Share Units ("DSU's")

The following table summarizes the information about DSU's at June 30, 2004:

	Outstanding DSU's	Weighted Average Exercise Price *(C$)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	319,250	48.68
Granted, Directors	56,295	53.98
Granted, Senior Executives	1,145	55.71
Outstanding, End of Period	376,690	49.49
Exercisable, End of Period	295,472	50.86

NOTE 12
(continued)

D) Performance Share Units ("PSU's")

The following table summarizes the information about PSU's at June 30, 2004:

	Outstanding PSU's	Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**126,283**	**46.52**
Granted	**1,669,150**	**53.97**
Forfeited	**(34,768)**	**53.61**
Outstanding, End of Period	**1,760,665**	**53.44**
Exercisable, End of Period	**–**	**–**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**–**	**–**
Granted	**248,529**	**41.12**
Forfeited	**(6,599)**	**41.12**
Outstanding, End of Period	**241,930**	**41.12**
Exercisable, End of Period	**–**	**–**

NOTE 13

PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share:

	Three Months Ended			Six Months Ended	
	March 31,	June 30,		June 30,	
(millions)	2004	**2004**	2003	**2004**	2003
Weighted Average Common Shares					
Outstanding – Basic	460.9	**460.3**	480.6	**460.6**	480.3
Effect of Dilutive Securities	6.2	**5.2**	3.8	**6.2**	3.5
Weighted Average Common Shares					
Outstanding – Diluted	467.1	**465.5**	484.4	**466.8**	483.8

NOTE 14

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As a means of managing commodity price volatility, the Company has entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments only.

As discussed in Note 2, on January 1, 2004, the fair value of all outstanding financial instruments that were not considered accounting hedges was recorded on the Consolidated Balance Sheet with an offsetting net deferred loss amount. The deferred loss is recognized into net earnings over the life of the related contracts. Changes in fair value after that time are recorded on the Consolidated Balance Sheet with the associated unrealized gain or loss recorded in net earnings. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2004 to June 30, 2004:

		Acquired	Net Deferred Amounts Recognized on Transition	Fair Market Value	**Total Unrealized Gain/(Loss)**
Fair Value of Contracts, January 1, 2004	*(Note 2)*	$ –	$ 235	$ (235)	**$ –**
Fair Value of Contracts Acquired with Tom Brown, Inc.		16	–	(16)	**–**
Change in Fair Value of Contracts Still Outstanding at June 30, 2004		–	–	(267)	**(267)**
Fair Value of Contracts Realized During the Period		–	(191)	191	**–**
Fair Value of Contracts Entered into During the Period		–	–	(264)	**(264)**
Fair Value of Contracts Outstanding		16	44	(591)	**(531)**
Premiums Paid on Collars and Options		–	–	27	**–**
Fair Value of Contracts Outstanding and Premiums Paid, End of Period		$ 16	$ 44	$ (564)	**$ (531)**

The total realized loss recognized in net earnings for the quarter and year-to-date ended June 30, 2004 was $263 million ($177 million, net of tax) and $408 million ($276 million, net of tax), respectively.

At June 30, 2004, the net deferred amounts recognized on transition and the risk management amounts are recorded on the Consolidated Balance Sheet as follows:

	As at June 30, 2004
Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	**$ 139**
Investments and other assets	**3**
Accounts payable and accrued liabilities	**37**
Other liabilities	**61**
Total Net Deferred Loss	**$ 44**
Risk Management	
Current asset	**$ 64**
Long-term asset	**91**
Current liability	**597**
Long-term liability	**122**
Total Net Risk Management Liability	**$ (564)**

A summary of all unrealized estimated fair value financial positions is as follows:

	As at June 30, 2004
Commodity Price Risk	
Natural gas	**$ (197)**
Crude oil	**(400)**
Power	**8**
Foreign Currency Risk	**–**
Interest Rate Risk	**25**
	$ (564)

Information with respect to power, foreign currency risk and interest rate risk contracts in place at December 31, 2003 is disclosed in Note 17 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at June 30, 2004.

NOTE 14
(continued)

Natural Gas

At June 30, 2004, the Company's gas risk management activities for financial contracts had an unrealized loss of $(181) million and a fair market value position of $(197) million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
Fixed AECO price	457	2004	6.19	C$/Mcf	$ (61)
NYMEX Fixed price	753	2004	5.13	US$/Mcf	(159)
Chicago Fixed price	40	2004	5.42	US$/Mcf	(7)
Colorado Interstate Gas (CIG)	53	2004	5.51	US$/Mcf	2
Houston Ship Channel (HSC)	60	2004	5.92	US$/Mcf	(3)
Mid-Continent	5	2004	4.62	US$/Mcf	(1)
Rockies	20	2004	5.36	US$/Mcf	–
San Juan	17	2004	4.98	US$/Mcf	(2)
Texas Oklahoma	5	2004	4.80	US$/Mcf	(1)
Waha	25	2004	5.50	US$/Mcf	(2)
NYMEX Fixed Price	170	2005	5.65	US$/Mcf	(30)
Colorado Interstate Gas (CIG)	114	2005	4.87	US$/Mcf	(18)
Houston Ship Channel (HSC)	40	2005	5.46	US$/Mcf	(7)
Rockies	30	2005	4.95	US$/Mcf	(5)
Waha	40	2005	5.16	US$/Mcf	(7)
NYMEX Fixed Price	195	2006	5.23	US$/Mcf	(24)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(12)
Houston Ship Channel (HSC)	90	2006	5.08	US$/Mcf	(12)
Rockies	35	2006	4.45	US$/Mcf	(5)
San Juan	16	2006	4.50	US$/Mcf	(2)
Waha	30	2006	4.79	US$/Mcf	(4)
Collars and Other Options					
AECO Collars	73	2004	5.34 – 7.52	C$/Mcf	(4)
NYMEX Collars	38	2004	4.40 – 5.79	US$/Mcf	(4)
Purchased NYMEX Put Options	10	2004	5.00	US$/Mcf	–
Other (1)	65	2004	4.21 – 6.16	US$/Mcf	(2)
Purchased NYMEX Put Options	47	2005	5.00	US$/Mcf	–
NYMEX 3-Way Call Spread	180	2005	5.00/6.69/7.69	US$/Mcf	(10)
Basis Contracts					
Fixed NYMEX to AECO Basis	345	2004	(0.55)	US$/Mcf	27
Fixed NYMEX to Rockies Basis	299	2004	(0.50)	US$/Mcf	19
Fixed NYMEX to Chicago Basis	10	2004	0.09	US$/Mcf	–
Fixed NYMEX to San Juan Basis	71	2004	(0.63)	US$/Mcf	2
Fixed NYMEX to CIG Basis	37	2004	(0.77)	US$/Mcf	2
Fixed Rockies to CIG Basis	50	2004	(0.10)	US$/Mcf	–
Other (1)	44	2004	(0.36)	US$/Mcf	–
Fixed NYMEX to AECO basis	877	2005	(0.66)	US$/Mcf	51
Fixed NYMEX to Rockies basis	268	2005	(0.49)	US$/Mcf	24
Fixed NYMEX to San Juan basis	90	2005	(0.63)	US$/Mcf	1
Fixed NYMEX to CIG basis	137	2005	(0.77)	US$/Mcf	3
Fixed Rockies to CIG basis	50	2005	(0.10)	US$/Mcf	–
Other (1)	118	2005	(0.26)	US$/Mcf	–
Fixed NYMEX to AECO basis	402	2006-2008	(0.65)	US$/Mcf	31
Fixed NYMEX to Rockies basis	162	2006-2008	(0.56)	US$/Mcf	21
Fixed NYMEX to San Juan basis	62	2006	(0.63)	US$/Mcf	1
Fixed Rockies to CIG basis	31	2006-2007	(0.10)	US$/Mcf	–
Fixed NYMEX to CIG basis	279	2006	(0.83)	US$/Mcf	(1)
Other (1)	70	2006	(0.30)	US$/Mcf	–
Total Sales Contracts					$ (199)

(1) For the Collars and Other Options, these Other contracts relate to various price points at Permian, San Juan, Waha, Colorado Interstate Gas (CIG), Houston Ship (HSC), Mid-Continent, Rockies and Texas Oklahoma while for the Basis Contracts, they relate to HSC, Mid-Continent, Waha and Ventura.

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Total Sales Contracts *(continued)*					$ (199)
Purchase Contracts					
Basis Contracts					
Fixed NYMEX to AECO Basis	112	2004	(0.96)	US$/Mcf	(2)
Premiums Paid on 3-Way Call Spread					1
Total Natural Gas Financial Positions					(200)
Gas Storage Financial Positions					(4)
Gas Marketing Financial Positions (2)					7
Total Fair Value Positions					(197)
Contracts Acquired					16
Total Unrealized Loss on Financial Contracts					$ (181)

(2) The gas marketing activities are part of the daily ongoing operations of the Company's proprietary production management.

Crude Oil

At June 30, 2004, the Company's oil risk management activities for all financial contracts had an unrealized loss of $(426) million and a fair market value position of $(400) million. The contracts were as follows:

	Notional Volumes *(bbl/d)*	Term	Average Price *(US$/bbl)*	Fair Market Value
Fixed WTI NYMEX Price	62,500	2004	23.13	$ (156)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(127)
Purchased WTI NYMEX Call Options	111,000	2004	46.64	(10)
Fixed WTI NYMEX Price	45,000	2005	28.41	(105)
3-Way Put Spread	10,000	2005	20.00/25.00/28.78	(25)
Purchased WTI NYMEX Call Options	38,000	2005	49.76	(4)
				(427)
Crude Oil Marketing Financial Positions (1)				1
Total Unrealized Loss on Financial Contracts				(426)
Premiums Paid on Call Options				26
Total Fair Value Positions				$ (400)

(1) The crude oil marketing activities are part of the daily ongoing operations of the Company's proprietary production management.

NOTE 15

SUBSEQUENT EVENT

In July 2004, the Company entered into agreements to sell certain crude oil and natural gas assets in Canada for total proceeds of approximately $660 million. These sales are expected to close in the third quarter.

NOTE 16

RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2004.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

(US$ millions, except per share amounts)	2004 Year-to-date	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Cash Flow	**2,126**	**1,131**	995	4,459	1,254	977	1,007	1,221
Per share – Basic	**4.62**	**2.46**	2.16	9.41	2.71	2.06	2.10	2.54
– Diluted	**4.55**	**2.43**	2.13	9.30	2.69	2.04	2.08	2.52
Net Earnings	**540**	**250**	290	2,360	426	290	807	837
Per share – Basic	**1.17**	**0.54**	0.63	4.98	0.92	0.61	1.68	1.74
– Diluted	**1.16**	**0.54**	0.62	4.92	0.91	0.61	1.67	1.73
Net Earnings from Continuing Operations	**540**	**250**	290	2,167	426	286	805	650
Per share – Basic	**1.17**	**0.54**	0.63	4.57	0.92	0.60	1.67	1.35
– Diluted	**1.16**	**0.54**	0.62	4.52	0.91	0.60	1.66	1.34
Operating Earnings *	**844**	**379**	465	1,375	316	274	275	510
Per share – Diluted	**1.81**	**0.81**	1.00	2.87	0.68	0.57	0.56	1.05
Foreign Exchange Rates *(US$ per C$1)*								
Average	**0.747**	**0.736**	0.759	0.716	0.760	0.725	0.715	0.662
Period end	**0.746**	**0.746**	0.763	0.774	0.774	0.741	0.738	0.681

* Operating Earnings is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

Common Shares Information	2004 Year-to-date	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Common Shares Outstanding *(millions)*								
Period end	**461.0**	**461.0**	459.8	460.6	460.6	465.0	479.9	480.6
Average – Basic	**460.6**	**460.3**	460.9	474.1	462.3	473.4	480.6	479.9
Average – Diluted	**466.8**	**465.5**	467.1	479.7	465.9	477.9	484.4	484.3
Price Range *($ per share)*								
TSX – C$								
High	**59.73**	**59.73**	59.27	53.55	52.25	52.79	53.55	50.00
Low	**51.00**	**52.99**	51.00	44.60	44.60	47.49	45.26	45.74
Close	**57.62**	**57.62**	56.69	51.00	51.00	48.90	51.70	47.75
NYSE – US$								
High	**44.73**	**44.73**	44.25	40.08	40.08	38.34	39.63	33.50
Low	**38.05**	**38.05**	38.36	29.91	33.46	34.00	30.45	29.91
Close	**43.16**	**43.16**	43.12	39.44	39.44	36.38	38.37	32.36
Share Volume Traded *(millions)*	**250.0**	**121.2**	128.8	476.4	141.1	117.9	107.2	110.2
Share Value Traded *(US$ millions weekly average)*	**398.2**	**392.9**	403.7	317.6	397.3	321.5	289.9	266.7

Financial Metrics	
Debt to Capitalization **	**43%**
Debt to EBITDA **	**2.0x**
Return on Capital Employed	**8%**
Return on Common Equity	**11%**

** Includes pro forma disposition proceeds of approximately US$660 million.

Financial Statistics (continued)

Net Capital Investment *(US$ millions)*	2004	2003
Upstream		
Canada	**$ 1,684**	$ 1,199
United States	**526**	336
Ecuador	**110**	107
United Kingdom	**208**	26
Other Countries	**34**	48
	2,562	1,716
Midstream & Marketing	**25**	96
Corporate	**18**	31
Core Capital	**2,605**	1,843
Acquisitions		
Upstream		
Property		
Canada	**19**	187
United States	**–**	10
United Kingdom	**121**	–
Corporate		
Vintage	**–**	116
Petrovera	**253**	–
Tom Brown, Inc.	**2,335**	–
Midstream & Marketing	**–**	53
Disposition		
Upstream		
Property		
Canada	**(133)**	(19)
United States	**3**	–
Corporate		
Petrovera	**(541)**	–
Midstream & Marketing	**(1)**	–
Net Acquisition and Disposition activity	**2,056**	347
Net Capital Investment – Continuing Operations	**4,661**	2,190
Discontinued Operations	**–**	(1,278)
Total Net Capital Investment	**$ 4,661**	$ 912

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics – After Royalties

	2004			2003				
Sales Volumes	**Year-to-date**	**Q2**	**Q1**	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas *(MMcf/d)*								
Canada								
Production	**2,089**	**2,177**	2,000	1,935	2,008	1,914	1,899	1,922
Inventory withdrawal	–	–	–	30	–	–	–	120
Canada Sales	**2,089**	**2,177**	2,000	1,965	2,008	1,914	1,899	2,042
United States	**754**	**824**	684	588	654	604	558	534
United Kingdom	**32**	**36**	28	13	20	7	12	13
	2,875	**3,037**	2,712	2,566	2,682	2,525	2,469	2,589
Oil and Natural Gas Liquids *(bbls/d)*								
North America								
Light and Medium Oil	**59,694**	**64,448**	54,940	54,459	56,585	54,597	52,733	53,890
Heavy Oil	**83,814**	**79,899**	87,729	87,867	95,059	94,985	82,001	79,171
Natural Gas Liquids*								
Canada	**13,780**	**13,588**	13,971	14,278	13,348	13,758	14,740	15,291
United States	**10,995**	**12,752**	9,237	9,291	9,479	9,530	10,194	7,943
Total North America	**168,283**	**170,687**	165,877	165,895	174,471	172,870	159,668	156,295
Ecuador								
Production	**77,348**	**78,376**	76,320	51,089	72,731	54,582	36,754	39,893
Transferred to OCP Pipeline**	**–**	**–**	–	(3,213)	–	(4,919)	(2,039)	(5,941)
Over / (under) lifting	**2,295**	**(73)**	4,662	(1,355)	4,621	(9,856)	2,506	(2,679)
Ecuador Sales	**79,643**	**78,303**	80,982	46,521	77,352	39,807	37,221	31,273
United Kingdom	**19,408**	**20,728**	18,088	10,128	15,067	5,813	9,019	10,610
Total Oil and Natural Gas Liquids	**267,334**	**269,718**	264,947	222,544	266,890	218,490	205,908	198,178
Total *(BOE/d)*	**746,501**	**775,885**	716,947	650,211	713,890	639,323	617,408	629,678

* Natural gas liquids include condensate volumes.

** Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

Operating Statistics – After Royalties (continued)

Per-unit Results *(excluding impact of financial hedging)*	2004 Year-to-date	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Produced Gas – Canada *(US$/Mcf)*								
Price, net of royalties	**5.21**	**5.20**	5.21	4.87	4.41	4.61	4.92	5.53
Production and mineral taxes	**0.07**	**0.07**	0.08	0.07	0.10	0.08	0.08	0.02
Transportation and selling	**0.39**	**0.35**	0.44	0.38	0.44	0.40	0.35	0.33
Operating expenses	**0.52**	**0.49**	0.56	0.48	0.45	0.50	0.47	0.48
Netback	**4.23**	**4.29**	4.13	3.94	3.42	3.63	4.02	4.70
Produced Gas – United States *(US$/Mcf)*								
Price, net of royalties	**5.57**	**5.72**	5.39	4.88	4.71	4.82	4.74	5.32
Production and mineral taxes	**0.67**	**0.80**	0.51	0.47	0.42	0.46	0.46	0.57
Transportation and selling	**0.36**	**0.34**	0.39	0.40	0.51	0.39	0.36	0.32
Operating expenses	**0.36**	**0.37**	0.33	0.28	0.29	0.33	0.31	0.20
Netback	**4.18**	**4.21**	4.16	3.73	3.49	3.64	3.61	4.23
Produced Gas – Total North America *(US$/Mcf)*								
Price, net of royalties	**5.30**	**5.34**	5.26	4.87	4.49	4.66	4.88	5.49
Production and mineral taxes	**0.23**	**0.27**	0.19	0.16	0.18	0.17	0.17	0.14
Transportation and selling	**0.39**	**0.35**	0.43	0.39	0.46	0.40	0.35	0.33
Operating expenses	**0.48**	**0.46**	0.50	0.43	0.41	0.46	0.43	0.42
Netback	**4.20**	**4.26**	4.14	3.89	3.44	3.63	3.93	4.60
Light and Medium Oil – Canada *(US$/bbl)*								
Price, net of royalties	**31.27**	**32.43**	29.92	26.61	25.53	24.31	27.43	29.34
Production and mineral taxes	**0.82**	**0.79**	0.86	0.29	0.73	(1.35)	0.71	1.08
Transportation and selling	**0.96**	**0.76**	1.19	1.42	1.33	0.71	1.73	1.95
Operating expenses	**5.32**	**4.84**	5.87	6.00	6.28	5.93	6.07	5.68
Netback	**24.17**	**26.04**	22.00	18.90	17.19	19.02	18.92	20.63
Heavy Oil – Canada *(US$/bbl)*								
Price, net of royalties	**21.89**	**22.35**	21.48	19.61	18.43	17.93	20.07	22.62
Production and mineral taxes	**0.03**	**(0.01)**	0.06	(0.03)	0.09	(0.49)	0.34	(0.02)
Transportation and selling	**1.60**	**1.50**	1.69	1.24	1.54	0.58	1.37	1.56
Operating expenses	**5.15**	**4.82**	5.44	5.67	4.95	5.93	6.18	5.70
Netback	**15.11**	**16.04**	14.29	12.73	11.85	11.91	12.18	15.38
Total Crude Oil – Canada *(US$/bbl)*								
Price, net of royalties	**25.79**	**26.85**	24.73	22.29	21.08	20.26	22.95	25.34
Production and mineral taxes	**0.36**	**0.35**	0.37	0.09	0.33	(0.80)	0.49	0.43
Transportation and selling	**1.34**	**1.17**	1.50	1.31	1.46	0.63	1.51	1.72
Operating expenses	**5.22**	**4.83**	5.61	5.80	5.45	5.93	6.13	5.70
Netback	**18.87**	**20.50**	17.25	15.09	13.84	14.50	14.82	17.49

Operating Statistics – After Royalties (continued)

Per-unit Results *(excluding impact of financial hedging) (continued)*	2004 Year-to-date	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Natural Gas Liquids – Canada *(US$/bbl)*								
Price, net of royalties	**27.87**	**28.48**	27.27	24.26	25.13	23.52	21.02	27.31
Production and mineral taxes	**–**	**–**	–	–	–	–	–	–
Transportation and selling	**0.35**	**0.35**	0.35	0.17	0.13	0.58	–	–
Netback	**27.52**	**28.13**	26.92	24.09	25.00	22.94	21.02	27.31
Natural Gas Liquids – United States *(US$/bbl)*								
Price, net of royalties	**32.86**	**32.93**	32.77	26.97	26.68	25.50	24.64	32.18
Production and mineral taxes	**3.58**	**3.93**	3.09	2.03	2.69	2.64	1.21	1.55
Transportation and selling	**–**	**–**	–	–	–	–	–	–
Netback	**29.28**	**29.00**	29.68	24.94	23.99	22.86	23.43	30.63
Natural Gas Liquids – Total North America *(US$/bbl)*								
Price, net of royalties	**30.08**	**30.63**	29.46	25.33	25.77	24.33	22.50	28.98
Production and mineral taxes	**1.59**	**1.90**	1.23	0.80	1.12	1.08	0.50	0.53
Transportation and selling	**0.20**	**0.18**	0.21	0.10	0.08	0.35	–	–
Netback	**28.29**	**28.55**	28.02	24.43	24.57	22.90	22.00	28.45
Total Liquids – Canada *(US$/bbl)*								
Price, net of royalties	**25.97**	**26.99**	24.95	22.47	21.41	20.54	22.76	25.55
Production and mineral taxes	**0.33**	**0.32**	0.34	0.08	0.30	(0.73)	0.44	0.38
Transportation and selling	**1.25**	**1.10**	1.40	1.21	1.36	0.62	1.36	1.54
Operating expenses	**4.76**	**4.42**	5.11	5.27	5.01	5.43	5.53	5.11
Netback	**19.63**	**21.15**	18.10	15.91	14.74	15.22	15.43	18.52
Ecuador Oil *(US$/bbl)*								
Price, net of royalties	**25.77**	**27.78**	23.82	24.21	23.57	22.13	22.31	30.86
Production and mineral taxes	**1.60**	**1.84**	1.37	1.47	1.06	0.45	1.11	4.27
Transportation and selling	**2.28**	**1.92**	2.63	2.56	2.81	2.36	2.41	2.35
Operating expenses	**4.09**	**4.14**	4.04	4.84	4.62	4.33	5.63	5.09
Netback	**17.80**	**19.88**	15.78	15.34	15.08	14.99	13.16	19.15
United Kingdom Oil *(US$/bbl)*								
Price, net of royalties	**33.03**	**34.68**	31.11	28.11	27.05	27.92	27.17	30.61
Transportation and selling	**1.89**	**1.85**	1.94	1.97	1.70	1.98	1.86	2.45
Operating expenses	**6.00**	**7.84**	3.86	5.09	6.23	6.55	4.69	2.92
Netback	**25.14**	**24.99**	25.31	21.05	19.12	19.39	20.62	25.24
Total Liquids – All Countries *(US$/bbl)*								
Price, net of royalties	**26.63**	**28.00**	25.23	23.25	22.51	21.22	22.93	26.89
Production and mineral taxes	**0.82**	**0.91**	0.73	0.45	0.59	(0.35)	0.58	1.02
Transportation and selling	**1.55**	**1.34**	1.76	1.47	1.74	0.95	1.51	1.64
Operating expenses	**4.41**	**4.33**	4.49	4.93	4.75	5.01	5.22	4.77
Netback	**19.85**	**21.42**	18.25	16.40	15.43	15.61	15.62	19.46

Operating Statistics – After Royalties (continued)

Impact of Financial Hedging	2004 Year-to-date	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Natural gas *($/Mcf)*	**(0.17)**	**(0.25)**	(0.08)	(0.10)	0.16	(0.06)	(0.25)	(0.25)
Liquids *($/bbl)*	**(6.04)**	**(6.69)**	(5.39)	(2.54)	(2.15)	(2.18)	(1.61)	(4.45)
Total *($/BOE)*	**(2.82)**	**(3.31)**	(2.29)	(1.25)	(0.22)	(0.99)	(1.55)	(2.43)

Average Royalty Rates *(excluding impact of financial hedging)*	2004 Year-to-date	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Produced Gas								
Canada	**13.0%**	**12.7%**	13.3%	12.9%	12.2%	12.9%	14.2%	12.4%
United States	**20.3%**	**21.1%**	19.3%	20.0%	19.5%	20.2%	20.1%	20.5%
Crude Oil								
Canada and United States	**10.5%**	**11.6%**	9.4%	10.3%	9.7%	9.0%	10.7%	11.8%
Ecuador	**27.0%**	**26.5%**	27.4%	25.6%	25.4%	25.7%	24.9%	26.9%
Natural Gas Liquids								
Canada	**13.9%**	**13.1%**	14.8%	17.5%	14.7%	16.6%	18.0%	20.2%
United States	**20.1%**	**20.7%**	19.2%	17.6%	17.5%	17.0%	17.3%	18.5%
Total Upstream	**14.7%**	**14.3%**	15.2%	14.5%	14.4%	14.2%	15.1%	14.4%

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