T S X / N Y S E S Y M B O L : E C A

EnCana Corporation

THIRD QUARTER INTERIM REPORT

For the period ended

September 30, 2004

Q3

ENCANA'S THIRD QUARTER OIL AND GAS SALES UP 22 PERCENT TO 781,000 BOE PER DAY; CASH FLOW EXCEEDS US$1.36 BILLION

CALGARY, ALBERTA (OCTOBER 27, 2004) – EnCana Corporation (TSX & NYSE: ECA) today reported third quarter sales growth of more than 22 percent to 781,000 barrels of oil equivalent (BOE) per day, a 40 percent increase in cash flow to US$1,363 million, or $2.92 per share diluted and a doubling of operating earnings to $559 million, or $1.20 per share diluted, compared to the third 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-royalties basis. All figures are in U.S. dollars unless otherwise noted.

THIRD QUARTER OPERATING EARNINGS RISE 104 PERCENT TO $559 MILLION

EnCana's third quarter operating earnings of $559 million, or $1.20 per share diluted, were up 104 percent from $274 million in the third quarter of 2003. Third quarter operating earnings exclude an after-tax unrealized mark-to-market loss of $321 million related to price hedges and an after-tax unrealized gain of $155 million due to changes in foreign exchange on translation related to U.S. dollar denominated debt. After inclusion of these non-cash items, net earnings in the third quarter were $393 million, or 84 cents per share diluted, up 36 percent from the third quarter of 2003. Third quarter pre-tax cash flow was $1,487 million, up 45 percent from the same period in 2003. Third quarter after-tax cash flow of $1,363 million, or $2.92 per share diluted, includes a cash tax provision of $124 million, compared with $51 million of cash taxes in the same 2003 period. Third quarter revenues net of royalties were $2,458 million.

ENCANA™

OIL & NGLs SALES
(bbls/d)

A 19 percent sales increase was driven largely by growth in Canadian oilsands, Ecuador and the U.K.

THIRD QUARTER GAS SALES UP 24 PERCENT IN PAST YEAR; OIL AND NGLS SALES UP 19 PERCENT

Contributing to EnCana's growth in operating earnings, third quarter natural gas sales increased 24 percent to 3.13 billion cubic feet per day compared to the third quarter of 2003. The increase was mainly driven by strong organic sales growth from resource plays at Greater Sierra, Cutbank Ridge and Southern Plains shallow gas in Canada and Mamm Creek in the U.S. Rockies, plus the acquisition of Tom Brown, Inc. (Tom Brown), which added an average of 275 million cubic feet per day during the quarter. EnCana's third quarter oil and NGLs sales grew 19 percent to 259,000 barrels per day driven largely by sales growth from Canadian oilsands, Ecuador and the U.K. North Sea. Operating costs were $3.38 per BOE, down 4 percent from the third quarter of 2003. EnCana drilled 1,314 net wells in the third quarter. Core capital investment, excluding acquisitions and divestitures, was approximately $1.1 billion during the quarter.

SALES 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, unchanged from the company's most recent guidance published in June 2004.

"EnCana continues to create exceptional value through investments in our portfolio of low-cost, long-life, North American resource plays. These unconventional assets are delivering unconventional production growth. In 2004 EnCana expects to achieve 15 percent sales growth, 80 percent of which is organic. Given our share buyback program in 2003 and 2004 to date, this would result in year-over-year sales growth of about 20 percent per share," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

THIRD QUARTER GAS PRICE REALIZATIONS UP 11 PERCENT, OIL AND NGLS PRICE REALIZATIONS UP 55 PERCENT

Third quarter realized pre-hedging North American natural gas prices were up about 11 percent from the third quarter of 2003 to $5.18 per thousand cubic feet. Realized pre-hedging oil and NGLs prices were up about 55 percent from the third quarter of 2003 to $32.83 per barrel.

GAS SALES
(MMcf/d)

Third quarter sales increased 24 percent to more than 3.1 billion cubic feet per day, comprised largely of organic growth from EnCana's portfolio of North American resource plays.

NINE MONTHS CASH FLOW EXCEEDS $3.4 BILLION, SALES UP 21 PERCENT

Pre-tax cash flow in the first nine months was $4,048 million, up 26 percent from the same 2003 period. After-tax, EnCana generated $3,489 million of cash flow, or $7.47 per share diluted, in the first nine months of 2004. This includes a cash tax provision in the first nine months of 2004 of $559 million, compared with a cash tax provision of $17 million in the same 2003 period. Daily sales in the first nine months averaged 758,000 BOE, up 21 percent from the first nine months of 2003. Daily sales were comprised of 2.96 billion cubic feet of gas and 265,000 barrels of oil and NGLs. In the first nine months, EnCana drilled 3,998 net wells, about 70 percent of the 5,500 net wells planned for 2004. Core capital investment, excluding acquisitions and divestitures, was $3,703 million for the first nine months of 2004.

OPERATING EARNINGS IN THE FIRST NINE MONTHS WERE $1,403 MILLION, UP 32 PERCENT

In the first nine months of 2004, EnCana achieved operating earnings of $1,403 million, or $3.00 per share diluted, up 32 percent from the first nine months of 2003. Net earnings in the first nine months were $933 million, or $2.00 per share diluted, which includes three non-cash items: an after-tax unrealized mark-to-market loss of $677 million, an after-tax unrealized gain on foreign exchange on US$ denominated debt issued in Canada of $98 million, and a $109 million gain due to tax rate changes. Nine month operating costs were $3.39 per BOE compared to $3.41 per BOE in the same period of 2003, which is in line with the full year 2004 operating cost forecast of between $3.30 and $3.50 per BOE. In the first nine months of 2004, revenues net of royalties were $8,026 million.

US$ and U.S. protocols

FINANCIAL HIGHLIGHTS

Consolidated EnCana Highlights

(as at and for the period ended September 30) *(US$ millions, except per share amounts)*	**Q3 2004**	Q3 2003	% Δ	**9 months 2004**	9 months 2003	% Δ
REVENUES, NET OF ROYALTIES	**2,458**	2,291	+7	**8,026**	7,366	+9
OPERATING EBITDA [1]	**1,484**	1,072	+38	**4,188**	3,361	+25
CASH FLOW	**1,363**	977	+40	**3,489**	3,205	+9
Per share – basic	**2.95**	2.06	+43	**7.57**	6.71	+13
Per share – diluted	**2.92**	2.04	+43	**7.47**	6.63	+13
Add back:						
CASH TAX	**124**	51	+143	**559**	17	+3,188
PRE-TAX CASH FLOW	**1,487**	1,028	+45	**4,048**	3,222	+26
CAPITAL INVESTMENT						
Core capital	**1,098**	1,340	–18	**3,703**	3,183	+16
Net acquisitions and divestitures [2]	**(891)**	96	–1,028	**1,165**	443	+163
Net capital investment – continuing operations	**207**	1,436	–86	**4,868**	3,626	+34
NET EARNINGS	**393**	290	+36	**933**	1,934	–52
Per share – basic	**0.85**	0.61	+39	**2.02**	4.05	–50
Per share – diluted	**0.84**	0.61	+38	**2.00**	4.00	–50
NET EARNINGS FROM CONTINUING OPERATIONS	**393**	286	+37	**933**	1,741	–46
Per share – basic	**0.85**	0.60	+42	**2.02**	3.64	–45
Per share – diluted	**0.84**	0.60	+40	**2.00**	3.60	–44
Add back:						
Unrealized mark-to-market accounting loss, after-tax	**321**	–	n/a	**677**	–	n/a
Add back:						
Unrealized foreign exchange (gain) related to translation of U.S. dollar debt, after-tax	**(155)**	(12)	+1,192	**(98)**	(320)	–69
Less:						
Future tax (recovery) due to tax rate change	**–**	–	n/a	**(109)**	(362)	–70
OPERATING EARNINGS	**559**	274	+104	**1,403**	1,059	+32
Per share – basic	**1.21**	0.58	+109	**3.04**	2.22	+37
Per share – diluted	**1.20**	0.57	+111	**3.00**	2.19	+37
COMMON SHARES at September 30 *(millions)*						
Weighted average (basic)	**461.7**	**473.4**	–2	**461.0**	478.0	–4
Weighted average (diluted)	**466.2**	**477.9**	–2	**467.1**	483.7	–3

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 ($1,028 million, year-to-date, before tax).

2 Includes both property and corporate acquisitions and divestitures.

OPERATING HIGHLIGHTS

Consolidated EnCana Highlights

(for the period ended September 30) (After royalties)	**Q3 2004**	Q3 2003	% Δ	**9 months 2004**	9 months 2003	% Δ
Natural gas *(MMcf/d)*						
Production (excluding Tom Brown)	**2,853**	2,525	+13	**2,824**	2,490	+13
Tom Brown production	**275**	–	n/a	**136**	–	n/a
Produced gas withdrawn from storage	–	–	–	–	38	n/a
Total natural gas sales *(MMcf/d)*	**3,128**	2,525	+24	**2,960**	2,528	+17
Oil and NGLs sales *(bbls/d)*						
North America	**169,673**	172,870	–2	**168,750**	163,008	+4
International	**89,735**	45,620	+97	**95,922**	44,595	+115
Total oil and NGLs sales *(bbls/d)*	**259,408**	218,490	+19	**264,672**	207,603	+27
Total sales *(BOE/d)*	**780,741**	639,323	+22	**758,005**	628,936	+21
Per share sales growth			+26			+26

Risk management strategy

EnCana's market risk mitigation strategy is designed to deliver greater predictability of cash flow and returns on investment. EnCana has hedged approximately 40 percent, about 1.3 billion cubic feet per day, of its projected fourth quarter 2004 natural gas sales at an average NYMEX equivalent price of $5.47 per thousand cubic feet. In addition, about 200 million cubic feet per day is subject to NYMEX collars at an average floor price of $4.43 per thousand cubic feet and an average ceiling price of $6.42 per thousand cubic feet. The company has also entered into longer term basis 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. In addition, for the balance of 2004, EnCana has also purchased call options with an average price of US$46.64, allowing EnCana to participate in oil price upside above this level. Detailed risk management positions at September 30, 2004 are presented in Note 14 to the unaudited third quarter consolidated financial statements. In the third quarter, EnCana's financial commodity and currency risk management measures resulted in realized gross revenue being lower by approximately $265 million, comprised of $221 million on oil sales and $44 million on gas sales.

Hedging impact expected to wane in 2005

Due to the dramatic increase in world oil prices in 2004 and EnCana's use of swaps and costless collars, the company experienced a substantial loss on its 2004 hedging program. About one quarter of EnCana's 2005 forecast oil sales is hedged with swaps or collars at approximately $29 per barrel. EnCana has also purchased call options for 2005 at an average price of $49.76 per barrel, allowing EnCana to participate in oil price upside above this level. About 17 percent of EnCana's 2005 forecast gas sales is hedged with swaps and collars at prices ranging from $4.90 to $6.70 per thousand cubic feet; on one third of these swaps/collars, call options have been purchased at an average price of $7.69, which will allow EnCana to participate in gas price upside above this level. EnCana has also purchased NYMEX gas put options with a floor price of $5.00 per thousand cubic feet covering a further 13 percent of forecast natural gas sales for 2005. EnCana will continue to use a variety of hedging instruments for its 2005 program including employing put options. These provide downside protection but do not limit the opportunity for the company to capture commodity price upside.

Resource plays continue to deliver strong growth

Across North America, EnCana's portfolio of long-life, low-decline resource plays continues to deliver double-digit oil and gas production growth. Daily third quarter production from EnCana's key North American resource plays has increased about 31 percent since the same period in 2003. This growth was generated primarily by increased gas production at four resource plays: Mamm Creek in Colorado, Greater Sierra and Cutbank Ridge in northeast B.C., and Southern Plains shallow gas on legacy Suffield and Palliser Blocks in southern Alberta. Oil production increases are from 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	Q3	Q2	Q1	Q4	Q3	Q2	Q1	YTD	Q3	Q2	Q1	Full year
Natural gas (*MMcf/d*)													
Canada													
Southern Plains shallow gas	580	**595**	590	554	538	509	499	483	1,330	**384**	416	530	2,366
Greater Sierra	236	**244**	247	216	175	144	136	118	169	**13**	21	135	199
Cutbank Ridge	37	**45**	41	22	6	2	2	2	33	**12**	4	17	20
Coalbed methane	13	**19**	11	10	7	3	3	2	451	**272**	98	81	267
U.S.A. [3]													
Jonah	384	**373**	387	394	389	376	356	375	49	**17**	21	11	59
Mamm Creek	205	**220**	203	191	175	126	112	86	196	**65**	65	66	259
North Texas	25	**31**	23	21	19	12	–	–	28	**10**	10	8	5
Oil *(Mbbls/d) (Canada)*													
Foster Creek	29	**29**	30	28	26	22	20	19	4	**–**	–	4	8
Pelican Lake	17	**22**	15	15	15	16	17	15	92	**33**	30	29	134

3 Excludes Tom Brown production.

EnCana's resource play production approaching 75 percent of North America portfolio

Throughout 2004, EnCana has been transitioning its North American asset portfolio to reduce the production contribution from mature conventional oil and gas assets in favour of increasing production from long-life, low-cost resource plays. This has been achieved three ways, first through the steady and focused investment in the company's established resource plays, mainly at Mamm Creek, Jonah, Greater Sierra, Cutbank Ridge and in Southern Plains shallow gas. Second, the $2.7 billion acquisition of Tom Brown, which included a portfolio of U.S. resource plays, and third, the divestment of mature, Canadian conventional oil and gas assets have accelerated this transition. To date in 2004, EnCana has divested of conventional assets which were producing approximately 129 million cubic feet per day and 30,600 barrels of oil per day, plus other non-core assets, generating proceeds of about $1.36 billion. As a result of these transactions and the company's focused investment strategy, EnCana's proportion of production from resource plays has increased from about 60 percent in 2003 to close to 75 percent. Additional divestitures of conventional assets in Western Canada are planned, and the vast majority of new capital is expected to be allocated towards resource plays.

EnCana 2004 Divestitures to September 30

			Production		
Asset	Completed	Price *($ million)*	Oil & NGLs *(bbls/d)*	Gas *(MMcf/d)*	BOE/d
Petrovera (net)	February	287	17,500	15	20,000
Northeast B.C.	April	84	–	12	2,000
New Mexico	July	235	900	18	3,900
East/Central Alberta oil	September	380	11,800	30	16,800
Northeast Alberta gas	August	226	–	43	7,250
Sauer Drilling Co.	July	37	–	–	–
Other	Various	109	400	11	2,250
Total Sold		**$ 1,358**	**30,600**	**129**	**52,200**

Future gas growth underpinned by 25 trillion cubic feet of natural gas resources

In 2004, EnCana is on track to produce more than 1 trillion cubic feet of natural gas. As of December 31, 2003 and including the Tom Brown reserves acquired in May 2004, EnCana's proved gas reserves exceeded 9.4 trillion cubic feet, yielding a reserve life index of approximately nine years. Beyond that, EnCana has identified approximately 16 trillion cubic feet of Unbooked Resource Potential, which EnCana defines as estimated quantities of hydrocarbons on existing company lands that are expected to be converted to proved reserves in the next five years.

"Our Unbooked Resource Potential is unique to EnCana because it is unique to resource plays. This potential is not dependent upon exploration success, as is the case with conventional plays. Rather this resource potential is on lands we currently own and where the resources have been estimated based on wells intended to be drilled over the next five years in geologically defined areas. EnCana has a proven track record of converting resource potential into proved reserves in a highly-efficient and cost effective manner. Our Unbooked Resource Potential is the key driver behind our steady growth in proved reserves and production. Together, the company's proved reserves and Unbooked Resource Potential for natural gas totals 25 trillion cubic feet, which represents close to 25 years – a quarter century – of clearly visible resource life at current production rates. This is what underpins EnCana's visible long-life, sustainable gas production growth," Morgan said.

CORPORATE DEVELOPMENTS

Dividend $0.10 per share

EnCana's board of directors has declared a quarterly dividend of $0.10 per share payable on December 31, 2004 to common shareholders of record as of December 15, 2004.

EnCana renews Normal Course Issuer Bid

EnCana has received approval for renewal of the company's Normal Course Issuer Bid from Toronto Stock Exchange (TSX). Under the renewed bid, EnCana may purchase for cancellation up to 23,114,500 of its common shares, representing five percent of the approximately 462 million common shares outstanding as at October 15, 2004. In the past 12 months under its previous Normal Course Issuer Bid, EnCana purchased 9,105,000 common shares, representing approximately two percent of the company's outstanding shares on October 14, 2003, at an average price of C$51.56 per common share. Purchases under the renewed bid may commence on October 29, 2004 and may be made until October 28, 2005. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies, and may also be made through the facilities of the New York Stock Exchange (NYSE) in accordance with its rules. Approval of the bid is not required from the NYSE. The price to be paid will be the market price at the time of acquisition. EnCana believes that the purchase of its common shares will help create value for the company's shareholders.

FINANCIAL STRENGTH

Balance Sheet Highlights

(US$ millions, except percent and ratio amounts)	**September 30 2004**	December 31 2003
Total assets	**29,673**	24,110
Long-term debt	**8,036**	6,088
Shareholders' equity	**12,083**	11,278
Net debt-to-capitalization ratio	**43%**	34%
Net Debt/Trailing EBITDA	**2.1 times**	1.3 times

To fund the Tom Brown acquisition, EnCana arranged a $3.0 billion credit facility, which was paid down to $846 million by the end of September. On July 29, EnCana made a public offering in the United States of US$250 million of 4.60% Notes due August 15, 2009 and US$750 million of 6.50% Notes due August 15, 2034. The net proceeds of the offering were used to repay a portion of EnCana's existing bank and commercial paper indebtedness. These investment grade debt securities are rated A- Outlook Negative by Standard & Poor's Ratings Services, Baa2 by Moody's Investors Service and A(low) negative trend by Dominion Bond Rating Service (DBRS).

In the third quarter of 2004, EnCana invested $1,098 million of core capital, acquisitions totaled $49 million and divestitures were $940 million, resulting in net capital investment of $207 million.

NON-GAAP MEASURES AND FORWARD-LOOKING STATEMENTS

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 news 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 $30 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 the portfolio includes the Buzzard oil field development. 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 use 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, reserves, and growth estimates for crude oil, natural gas and NGLs for 2004 and the next five years, including estimates calculated on a per share basis; the company's ability to achieve its 2004 sales guidance; 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, including over the next 25 years; potential dispositions of assets in 2004 and beyond, including anticipated proceeds therefrom and the dates for receipt thereof; anticipated purchases pursuant to the company's Normal Course Issuer Bid and the value of such bid to shareholders; the company's projected capital investment levels for 2004, and the source of funding therefor; anticipated returns on capital; 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 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; 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; the impact of the company's divestitures and potential divestitures on operating costs, netbacks and decline rates and references to potential exploration. 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.

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 nine months ended September 30, 2004, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2003. Readers are referred to the legal advisory detailing "Note Regarding Forward-Looking Statements" contained in the back of this MD&A. Certain definitions used in this MD&A are defined in the sections found at the back of this MD&A entitled "Note Regarding Oil and Gas Information" and "Note Regarding Currency, Protocols and Non-GAAP Measures". 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 October 26, 2004.

OVERVIEW

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

Third quarter 2004 compared to third quarter 2003:

- Upstream sales volumes increased by 22 percent to 780,741 BOE per day.
- North American natural gas prices (excluding financial hedges), averaged $5.18 per Mcf in 2004 compared to $4.66 per Mcf in 2003, an increase of 11 per cent.
- Liquids prices (excluding financial hedges), averaged $32.83 per barrel in 2004 compared to $21.22 in 2003, an increase of 55 percent.
- Operating expenses and corporate administration costs decreased on a BOE basis by $0.15 and $0.10 respectively.
- As part of the continuing alignment of the North American assets with EnCana's unconventional resource play strategy the Company completed $940 million in mature conventional property dispositions.
- Reduction in long-term debt (including current portion) during the third quarter in 2004 of $729 million.
- Realized financial commodity and currency hedge losses of approximately $265 million ($180 million after-tax) in 2004 compared to a $58 million ($40 million after-tax) loss for 2003.
- Mark-to-market accounting for derivative instruments resulted in a $497 million ($321 million after-tax) charge to earnings for unrealized losses in 2004 with no corresponding amount in 2003 since mark-to-market accounting was adopted as of January 1, 2004.
- A $193 million ($155 million after-tax) unrealized gain on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $15 million ($12 million after-tax) in 2003.
- A $95 million ($79 million after-tax) realized foreign exchange gain in 2004 compared to a realized gain of $5 million ($3 million after-tax) in 2003.
- Current income tax provision increased to $124 million in 2004 compared to a tax provision of $51 million in 2003, for a total increase in cash taxes of $73 million.

CONSOLIDATED FINANCIAL RESULTS

Consolidated Financial Summary

($ millions, except per share amounts)	Three Months Ended September 30 2004	2004 vs 2003	2003	Nine Months Ended September 30 2004	2004 vs 2003	2003	Year Ended 2003
Revenues, Net of Royalties	**$ 2,458**	**7%**	$ 2,291	**$ 8,026**	**9%**	$ 7,366	$ 10,216
Net Earnings from							
Continuing Operations	**393**	**37%**	286	**933**	**–46%**	1,741	2,167
– per share – basic	**0.85**	**42%**	0.60	**2.02**	**–45%**	3.64	4.57
– per share – diluted	**0.84**	**40%**	0.60	**2.00**	**–44%**	3.60	4.52
Net Earnings	**393**	**36%**	290	**933**	**–52%**	1,934	2,360
– per share – basic	**0.85**	**39%**	0.61	**2.02**	**–50%**	4.05	4.98
– per share – diluted	**0.84**	**38%**	0.61	**2.00**	**–50%**	4.00	4.92
Operating Earnings (1)	**559**	**104%**	274	**1,403**	**32%**	1,059	1,375
– per share – diluted	**1.20**	**111%**	0.57	**3.00**	**37%**	2.19	2.87
Cash Flow from							
Continuing Operations (2)	**1,363**	**40%**	973	**3,489**	**9%**	3,203	4,420
– per share – basic	**2.95**	**43%**	2.06	**7.57**	**13%**	6.70	9.32
– per share – diluted	**2.92**	**43%**	2.04	**7.47**	**13%**	6.62	9.21
Cash Flow (2)	**1,363**	**40%**	977	**3,489**	**9%**	3,205	4,459
– per share – basic	**2.95**	**43%**	2.06	**7.57**	**13%**	6.71	9.41
– per share – diluted	**2.92**	**43%**	2.04	**7.47**	**13%**	6.63	9.30

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

(2) Cash Flow from Continuing Operations and Cash Flow are non-GAAP measures and are discussed under "Cash Flow" in this MD&A.

Quarterly Summary

($ millions, except per share amounts)	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4
Revenues, Net of Royalties	**$ 2,458**	$ 2,718	$ 2,850	$ 2,850	$ 2,291	$ 2,332	$ 2,743	$ 2,116
Net Earnings from								
Continuing Operations	**393**	250	290	426	286	805	650	248
– per share – basic	**0.85**	0.54	0.63	0.92	0.60	1.67	1.35	0.52
– per share – diluted	**0.84**	0.54	0.62	0.91	0.60	1.66	1.34	0.51
Net Earnings	**393**	250	290	426	290	807	837	282
– per share – basic	**0.85**	0.54	0.63	0.92	0.61	1.68	1.74	0.59
– per share – diluted	**0.84**	0.54	0.62	0.91	0.61	1.67	1.73	0.58
Operating Earnings (1)	**559**	379	465	316	274	275	510	239
– per share – diluted	**1.20**	0.81	1.00	0.68	0.57	0.56	1.05	0.49
Cash Flow from								
Continuing Operations (2)	**1,363**	1,131	995	1,217	973	1,039	1,191	874
– per share – basic	**2.95**	2.46	2.16	2.63	2.06	2.16	2.48	1.83
– per share – diluted	**2.92**	2.43	2.13	2.61	2.04	2.14	2.46	1.81
Cash Flow (2)	**1,363**	1,131	995	1,254	977	1,007	1,221	935
– per share – basic	**2.95**	2.46	2.16	2.71	2.06	2.10	2.54	1.96
– per share – diluted	**2.92**	2.43	2.13	2.69	2.04	2.08	2.52	1.94

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

(2) Cash Flow from Continuing Operations and Cash Flow are non-GAAP measures and are discussed under "Cash Flow" in this MD&A.

CASH FLOW

EnCana's cash flow from continuing operations increased $390 million, or $0.88 per share diluted, in the third quarter of 2004 compared to the same period in 2003 and increased $286 million, or $0.85 per share diluted, during the first nine months of 2004 compared to the first nine months in 2003. Significant items are as follows:

Third quarter 2004 compared to third quarter 2003:

- Natural gas sales volumes increased 24 percent to 3,128 MMcf per day.
- Crude oil and NGLs sales volumes increased 19 percent to 259,408 barrels per day.
- North American natural gas prices (excluding financial hedges), were $5.18 per Mcf in 2004 compared to $4.66 per Mcf in 2003, an increase of 11 percent.
- Liquids prices (excluding financial hedges), are $32.83 per barrel in 2004 compared to $21.22 in 2003, an increase of 55 percent.
- Operating expenses are $3.38 per BOE in 2004 compared to $3.53 per BOE in 2003, a decrease of $0.15 per BOE.
- Corporate administration costs are $0.60 per BOE in 2004 compared to $0.70 per BOE in 2003, a reduction of $0.10 per BOE.
- Realized financial commodity and currency hedge losses are approximately $265 million ($180 million after-tax) in 2004 (comprised of $0.15 per Mcf on natural gas and $9.28 per barrel on liquids) compared to $58 million ($40 million after-tax) for 2003 (comprised of $0.06 per Mcf on natural gas and $2.18 per barrel on liquids).
- A $95 million ($79 million after-tax) realized foreign exchange gain in 2004 compared to a realized gain of $5 million ($3 million after-tax) in 2003 primarily as a result of the rise in the U.S./Canadian dollar exchange rate and its impact on Canadian issued U.S. denominated debt.
- Current tax provision increased by $73 million to $124 million in 2004 from $51 million in 2003 partially offsetting increased cash flow from higher volumes and prices.

Nine months ended September 2004 compared to nine months ended September 2003:

- Crude oil and NGLs sales volumes increased 27 percent to 264,672 barrels per day.
- Natural gas sales volumes increased 17 percent to 2,960 MMcf per day.
- North American natural gas prices (excluding financial hedges), are $5.26 per Mcf in 2004 compared to $5.01 per Mcf in 2003, an increase of 5 percent.
- Liquids prices (excluding financial hedges), are $28.67 per barrel in 2004 compared to $23.57 in 2003, an increase of 22 percent.
- Realized financial commodity and currency hedge losses are approximately $648 million ($439 million after-tax) in 2004 (comprised of $0.16 per Mcf on natural gas and $7.11 per barrel on liquids) compared to $283 million ($194 million after-tax) for 2003 (comprised of $0.19 per Mcf on natural gas and $2.71 per barrel on liquids).
- An $87 million ($71 million after-tax) realized foreign exchange gain in 2004 compared to a realized gain of $32 million ($18 million after-tax) in 2003 primarily as a result of the rise in the U.S./Canadian dollar exchange rate and its impact on Canadian issued U.S. denominated debt.
- Current tax provision increased by $542 million to $559 million in 2004 from $17 million in 2003 partially offsetting increased cash flow from higher volumes and prices.

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 increased $107 million, or $0.24 per share diluted in the third quarter of 2004 compared to the same period in 2003 and decreased $808 million, or $1.60 per share diluted during the first nine months of 2004 compared to the first nine months in 2003. In addition to the items affecting cash flow as detailed previously, significant items are:

Third quarter 2004 compared to third quarter 2003:

- Mark-to-market accounting for derivative instruments resulted in a $497 million ($321 million after-tax, $0.69 per share diluted) charge to earnings for unrealized losses in 2004 with no corresponding amount in 2003.
- A $193 million ($155 million after-tax, $0.33 per share diluted) unrealized gain on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $15 million ($12 million after-tax, $0.03 per share diluted) in 2003 as a result of a larger increase in the period end U.S./Canadian dollar exchange rate between June 30, 2004 and September 30, 2004 compared to the same period in 2003.

Nine months ended September 2004 compared to nine months ended September 2003:

- Unrealized mark-to-market losses of $1,028 million ($677 million after-tax, $1.44 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 a gain of $362 million, or $0.75 per share diluted, in 2003.
- A $122 million ($98 million after-tax, $0.21 per share diluted) unrealized gain on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $404 million ($320 million after-tax, $0.66 per share diluted) in 2003 as a result of a small increase in the period end U.S./Canadian dollar exchange rate between December 31, 2003 and September 30, 2004 compared to significant appreciation in the period end U.S./Canadian dollar exchange rate between December 31, 2002 and September 30, 2003.

Net earnings in the third quarter of 2003 include $4 million, or $0.01 per share diluted, from discontinued operations and on a year-to-date basis net earnings in 2003 include $193 million, or $0.40 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 $4.00 ($5.20 year-to-date) based on the increase in the average U.S./Canadian dollar exchange rate from the third quarter of 2003 of $0.725 ($0.701 year-to-date) to the third quarter of 2004 of $0.765 ($0.753 year-to-date). Revenues 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

($ millions)	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4
Net Earnings from Continuing Operations, as reported	**$ 393**	$ 250	$ 290	$ 426	$ 286	$ 805	$ 650	$ 248
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**321**	104	252	–	–	–	–	–
Add: Unrealized foreign exchange (gain) loss on translation of Canadian issued U.S. dollar debt (after-tax)	**(155)**	25	32	(113)	(12)	(168)	(140)	(6)
Add: Future tax (recovery) expense due to tax rate reductions	**–**	–	(109)	3	–	(362)	–	(3)
Operating Earnings (1)(3)	**$ 559**	$ 379	$ 465	$ 316	$ 274	$ 275	$ 510	$ 239

($ per Common Share – Diluted)	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4
Net Earnings from Continuing Operations, as reported	**$ 0.84**	$ 0.54	$ 0.62	$ 0.91	$ 0.60	$ 1.66	$ 1.34	$ 0.51
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**0.69**	0.22	0.54	–	–	–	–	–
Add: Unrealized foreign exchange (gain) loss on translation of Canadian issued U.S. dollar debt (after-tax)	**(0.33)**	0.05	0.07	(0.24)	(0.03)	(0.35)	(0.29)	(0.01)
Add: Future tax (recovery) expense due to tax rate reductions	**–**	–	(0.23)	0.01	–	(0.75)	–	(0.01)
Operating Earnings (1)(3)	**$ 1.20**	$ 0.81	$ 1.00	$ 0.68	$ 0.57	$ 0.56	$ 1.05	$ 0.49

(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.

Year-to-Date Summary of Operating Earnings

	Three Months Ended September 30			Nine Months Ended September 30		
($ millions)	**2004**	**2004 vs 2003**	2003	**2004**	**2004 vs 2003**	2003
Net Earnings from Continuing Operations, as reported	**$ 393**	**37%**	$ 286	**$ 933**	**–46%**	$ 1,741
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**321**	**–**	–	**677**	**–**	–
Add: Unrealized foreign exchange (gain) loss on translation of Canadian issued U.S. dollar debt (after-tax)	**(155)**	**1,192%**	(12)	**(98)**	**–69%**	(320)
Add: Future tax (recovery) expense due to tax rate reductions	**–**	**–**	–	**(109)**	**–70%**	(362)
Operating Earnings (1)(3)	**$ 559**	**104%**	$ 274	**$ 1,403**	**32%**	$ 1,059

($ per Common Share – Diluted)	**2004**	**2004 vs 2003**	2003	**2004**	**2004 vs 2003**	2003
Net Earnings from Continuing Operations, as reported	**$ 0.84**	**40%**	$ 0.60	**$ 2.00**	**–44%**	$ 3.60
Add: Unrealized mark-to-market accounting loss (after-tax) (2)	**0.69**	**–**	–	**1.44**	**–**	–
Add: Unrealized foreign exchange (gain) loss on translation of Canadian issued U.S. dollar debt (after-tax)	**(0.33)**	**1,000%**	(0.03)	**(0.21)**	**–68%**	(0.66)
Add: Future tax (recovery) expense due to tax rate reductions	**–**	**–**	–	**(0.23)**	**–69%**	(0.75)
Operating Earnings (1)(3)	**$ 1.20**	**111%**	$ 0.57	**$ 3.00**	**37%**	$ 2.19

(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 changes in the provision for current income tax. The following table has been prepared to disclose the quarterly cash flow from continuing operations and the current income tax provision.

	2004			2003				2002
($ millions)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Cash Flow from Continuing Operations	$ 1,363	$ 1,131	$ 995	$ 1,217	$ 973	$ 1,039	$ 1,191	$ 874
Current Income Tax (1)	$ 124	$ 203	$ 232	$ (73)	$ 51	$ (54)	$ 20	$ (107)

(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)*

	2004				2003			
(Three Months Ended September 30)	Produced Gas	Crude Oil and NGLs	Other	Total	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	$ 1,442	$ 562	$ 66	$ 2,070	$ 1,067	$ 384	$ 58	$ 1,509
Expenses								
Production and mineral taxes	69	28	–	97	40	(7)	–	33
Transportation and selling	102	38	–	140	94	20	–	114
Operating	131	113	60	304	107	100	51	258
Operating Cash Flow	$ 1,140	$ 383	$ 6	$ 1,529	$ 826	$ 271	$ 7	$ 1,104
Depreciation, depletion and amortization				672				502
Upstream Income				$ 857				$ 602

	2004				2003			
(Nine Months Ended September 30)	Produced Gas	Crude Oil and NGLs	Other	Total	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	$ 4,121	$ 1,562	$ 170	$ 5,853	$ 3,318	$ 1,186	$ 147	$ 4,651
Expenses								
Production and mineral taxes	188	70	–	258	110	21	–	131
Transportation and selling	334	114	–	448	255	76	–	331
Operating	377	329	155	861	301	284	134	719
Operating Cash Flow	$ 3,222	$ 1,049	$ 15	$ 4,286	$ 2,652	$ 805	$ 13	$ 3,470
Depreciation, depletion and amortization				1,947				1,444
Upstream Income				$ 2,339				$ 2,026

Consolidated Upstream Results

Overall results reflect a 22 percent increase in sales volumes of 141,418 BOE per day during the third quarter 2004 and a 21 percent increase in sales volumes of 129,069 BOE per day for the nine months ended September 30, 2004 compared with the same periods in 2003.

Revenues, net of royalties reflects the increase in natural gas and crude oil benchmark prices (see the "Business Environment" section of this MD&A) for both the third quarter and year-to-date results offset by the realized hedging losses. The effect of realized commodity and currency hedging losses was $265 million, or $3.69 per BOE, in the third quarter 2004 compared to $58 million, or $0.99 per BOE, in the three month period ended September 30, 2003. For the nine months ended September 30, 2004, realized commodity and currency hedge losses were $648 million, or $3.12 per BOE, compared to $283 million or $1.65 per BOE, for the same period in 2003.

Operating expenses in the third quarter of 2004 averaged $3.38 per BOE compared to $3.53 per BOE in 2003. For the nine months ended September 30, 2004, operating expenses were relatively unchanged at $3.39 per BOE compared to $3.41 per BOE for the same period in 2003.

Depreciation, depletion and amortization ("DD&A") expense increased by $170 million in the third quarter of 2004 and $503 million year-to-date September 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. On a BOE basis, excluding Other activities, DD&A rates were $9.27 per BOE for the third quarter of 2004 compared to $8.49 per BOE in the same period of 2003. DD&A rates were $9.23 per BOE for the first nine months of 2004 compared to $8.38 per BOE in the same period of 2003. Increased DD&A rates in the third 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 Tom Brown Inc. ("TBI"). DD&A rates for the nine months ended September 30, 2004 exclude the impairment of an Upstream international exploration prospect in Ghana which was recorded and disclosed in the second quarter of 2004.

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

	Three Months Ended September 30				Nine Months Ended September 30			
	2003 Revenues, Net of Royalties	Revenue Variances in: Price (2)	Revenue Variances in: Volume	2004 Revenues, Net of Royalties	2003 Revenues, Net of Royalties	Revenue Variances in: Price (2)	Revenue Variances in: Volume	2004 Revenues, Net of Royalties
Produced Gas								
Canada	$ 806	$ 62	$ 102	$ 970	$ 2,534	$ 132	$ 221	$ 2,887
United States	259	32	171	462	776	45	377	1,198
U.K. North Sea	2	–	8	10	8	4	24	36
Total Produced Gas	$ 1,067	$ 94	$ 281	$ 1,442	$ 3,318	$ 181	$ 622	$ 4,121
Crude Oil and NGLs								
Canada	$ 266	$ 64	$ (17)	$ 313	$ 809	$ 55	$ 19	$ 883
United States	22	10	18	50	69	19	27	115
Ecuador	81	4	74	159	243	(44)	233	432
U.K. North Sea	15	1	24	40	65	(3)	70	132
Total Crude Oil and NGLs	$ 384	$ 79	$ 99	$ 562	$ 1,186	$ 27	$ 349	$ 1,562

(1) Includes continuing operations only.

(2) Includes realized commodity hedging impacts.

The increase in sales volumes accounts for approximately 69 percent of the change in revenues, net of royalties in the third quarter of 2004 and approximately 82 percent for the first nine months of 2004. In the table above, impacts from price changes are reduced as a result of the period over period changes in realized commodity and currency hedge losses mentioned previously.

Quarterly Sales Volumes

(After Royalties)	2004 Q3[4]	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4
Produced Gas *(MMcf per day)*								
Canada								
Production	**2,138**	2,177	2,000	2,008	1,914	1,899	1,922	1,943
Inventory withdrawal	–	–	–	–	–	–	120	117
Canada Sales [5]	**2,138**	2,177	2,000	2,008	1,914	1,899	2,042	2,060
United States [5]	**958**	824	684	654	604	558	534	516
United Kingdom	**32**	36	28	20	7	12	13	8
	3,128	3,037	2,712	2,682	2,525	2,469	2,589	2,584
Oil and NGLs (*bbls per day*) [1]								
Canada Sales [5]	**154,726**	157,935	156,640	164,859	163,179	149,292	148,147	148,196
United States [5]	**14,947**	12,752	9,237	9,612	9,691	10,376	8,148	10,162
Ecuador								
Production	**76,567**	78,376	76,320	72,731	54,582	36,754	39,893	34,856
Transferred to OCP Pipeline [2]	–	–	–	–	(4,919)	(2,039)	(5,941)	–
Over / (under) lifting	**(1,721)**	(73)	4,662	4,621	(9,856)	2,506	(2,679)	1,044
Ecuador Sales	**74,846**	78,303	80,982	77,352	39,807	37,221	31,273	35,900
United Kingdom	**14,889**	20,728	18,088	15,067	5,813	9,019	10,610	7,786
	259,408	269,718	264,947	266,890	218,490	205,908	198,178	202,044
Total *(BOE per day)* [3]	**780,741**	775,885	716,947	713,890	639,323	617,408	629,678	632,711

(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.

(4) Quarterly volumes reflect decreases as a result of the 2004 property dispositions of 81 MMcf/d in natural gas and 22 Mbbls/d of liquids or a total of approximately 36 MBOE/d.

(5) Includes Tom Brown, Inc. sales volumes in 2004:

	Natural Gas *(MMcf/d)* Q3	Natural Gas *(MMcf/d)* Q2	Oil and NGLs *(bbls/d)* Q3	Oil and NGLs *(bbls/d)* Q2
Canada	18	9	923	511
United States	257	123	4,949	2,689
Total Volumes	275	132	5,872	3,200

Year-to-Date Sales Volumes Ended September 30

(After Royalties)	Three Months Ended September 30 2004[(4)]	2004 vs 2003	2003	Nine Months Ended September 30 2004[(5)]	2004 vs 2003	2003
Produced Gas *(MMcf per day)*						
Canada						
Production	**2,138**	**12%**	1,914	**2,105**	**10%**	1,913
Inventory withdrawal	**–**	**–**	–	**–**	**–**	38
Canada Sales [(6)]	**2,138**	**12%**	1,914	**2,105**	**8%**	1,951
United States [(6)]	**958**	**59%**	604	**823**	**45%**	566
United Kingdom	**32**	**357%**	7	**32**	**191%**	11
	3,128	**24%**	2,525	**2,960**	**17%**	2,528
Oil and NGLs *(bbls per day)* [(1)]						
Canada Sales [(6)]	**154,726**	**–5%**	163,179	**156,428**	**2%**	153,595
United States [(6)]	**14,947**	**54%**	9,691	**12,322**	**31%**	9,413
Ecuador						
Production	**76,567**	**40%**	54,582	**77,086**	**76%**	43,797
Transferred to OCP Pipeline [(2)]	**–**	**–**	(4,919)	**–**	**–**	(4,296)
Over / (under) lifting	**(1,721)**	**–**	(9,856)	**946**	**–**	(3,369)
Ecuador Sales	**74,846**	**88%**	39,807	**78,032**	**116%**	36,132
United Kingdom	**14,889**	**156%**	5,813	**17,890**	**111%**	8,463
	259,408	**19%**	218,490	**264,672**	**27%**	207,603
Total *(BOE per day)* [(3)]	**780,741**	**22%**	639,323	**758,005**	**21%**	628,936

(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.

(4) Quarterly volumes reflect decreases as a result of the 2004 property dispositions of 81 MMcf/d in natural gas and 22 Mbbls/d of liquids or a total of approximately 36 MBOE/d.

(5) Year-to-date volumes reflect decreases as a result of the 2004 property dispositions of 41 MMcf/d in natural gas and 16 Mbbls/d of liquids or a total of approximately 23 MBOE/d.

(6) 2004 Includes sales volumes from the acquisition of TBI. For the three months ended September 30 sales volumes from North America included 275 MMcf/d of natural gas and 5,872 bbls/d of liquids. For the nine months ended September 30 sales volumes from North America included 136 MMcf/d of natural gas and 3,035 bbls/d of liquids.

On a year-to-date basis, 2004 volumes are higher by 21 percent, or 129,069 BOE per day, compared to 2003. Increases in Canadian natural gas sales volumes in the third quarter and on a year-to-date basis in 2004 were primarily the result of successful resource play drilling programs at Greater Sierra and Cutbank Ridge in northeast British Columbia as well as southern plains shallow gas in Alberta. Third quarter 2004 natural gas sales volumes in the United States increased as a result of the TBI acquisition in the second quarter of 2004 and successful drilling program at Mamm Creek. Higher natural gas sales volumes in the United States for the first nine months of 2004 were primarily the result of successful resource play drilling programs at Mamm Creek, Jonah and North Texas and the TBI acquisition.

Increases in liquids sales volumes in the third quarter and for the first nine months of 2004 are primarily the result of the commencement of sales on the OCP Pipeline in Ecuador in September 2003 and the increased interests in the Scott and Telford fields in the United Kingdom. Increases in North American liquids sales in the third quarter of 2004 resulting from development at Foster Creek and Pelican Lake were more than offset by the reduction in volumes resulting from the Petrovera disposition in the first quarter of 2004 and additional non-core dispositions that closed in the third quarter of 2004. For the first nine months of 2004, North American liquids sales volumes were higher when compared to the same period in 2003 as a result of continued Foster Creek development, successful drilling programs at Suffield and positive response from the waterflood program at Pelican Lake offset partially by the Petrovera disposition and additional non-core dispositions in the third quarter of 2004.

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

(Three Months Ended September 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 (1)	**$ 5.10**	**11%**	$ 4.61	**$ 5.36**	**11%**	$ 4.82	**$ 3.84**	**47%**	$ 2.62
Expenses									
Production and mineral taxes	**0.09**	**13%**	0.08	**0.57**	**24%**	0.46	**–**	**–**	–
Transportation and selling	**0.37**	**–8%**	0.40	**0.26**	**–33%**	0.39	**2.34**	**–11%**	2.63
Operating	**0.50**	**–**	0.50	**0.36**	**9%**	0.33	**–**	**–**	–
Netback	**$ 4.14**		$ 3.63	**$ 4.17**		$ 3.64	**$ 1.50**		$ (0.01)
Gas Sales Volumes *(MMcf per day)*	**2,138**	**12%**	1,914	**958**	**59%**	604	**32**	**357%**	7

(1) Excludes realized commodity and currency hedge activities.

(Nine Months Ended September 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 (1)	**$ 5.17**	**3%**	$ 5.03	**$ 5.49**	**11%**	$ 4.95	**$ 4.07**	**47%**	$ 2.76
Expenses									
Production and mineral taxes	**0.08**	**33%**	0.06	**0.63**	**29%**	0.49	**–**	**–**	–
Transportation and selling (2)	**0.38**	**6%**	0.36	**0.32**	**–11%**	0.36	**2.28**	**6%**	2.16
Operating	**0.52**	**6%**	0.49	**0.36**	**29%**	0.28	**–**	**–**	–
Netback	**$ 4.19**		$ 4.12	**$ 4.18**		$ 3.82	**$ 1.79**		$ 0.60
Gas Sales Volumes (*MMcf per day*)	**2,105**	**8%**	1,951	**823**	**45%**	566	**32**	**191%**	11

(1) Excludes realized commodity and currency hedge activities.

(2) U.S. per unit transportation and selling costs in 2004 exclude a one-time payment of $21 million made to terminate a long-term physical delivery contract.

Average natural gas prices, excluding the impact of financial hedges, in the third quarter of 2004 reflect the increase in the benchmark NYMEX and AECO gas prices, offset partially by the increased applicable differentials compared to the same period of 2003. Higher benchmark NYMEX prices of 16 percent in the quarter (3 percent year-to-date) compared to the same period in 2003 was partially offset by increased natural gas price differentials. Realized commodity and currency hedging losses on natural gas were approximately $44 million, or $0.15 per Mcf in the third quarter of 2004 compared to a loss of approximately $14 million, or $0.06 per Mcf in the third quarter 2003. On a year-to-date basis to September 30, realized commodity and currency hedging losses on natural gas were approximately $133 million, or $0.16 per Mcf in 2004 compared to a loss of approximately $129 million, or $0.19 per Mcf in 2003.

Per unit production and mineral taxes in the U.S. in the quarter and for the nine months ended September 30, 2004 compared to the same periods in 2003 increased due to a combination of higher prices and a higher effective tax rate in Colorado caused by the significant growth in Colorado production.

On a year-to-date basis the per unit transportation and selling costs for Canadian natural gas have increased as a result of higher average distances to sales markets from production facilities and the increased U.S./Canadian exchange rate. Natural gas per unit transportation and selling costs for the U.S. have decreased in the quarter and for the nine months ended September 30, 2004 compared to the same periods in 2003 as a result of the TBI acquisition where a majority of the production is sold at the wellhead and does not incur additional transportation charges. The U.K. increase in transportation and selling expense year-to-date 2004 compared to the same period in 2003 reflects 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.

Canadian natural gas per unit operating expenses were unchanged in the third quarter of 2004 compared to the same period in 2003 but $0.03 higher on a year-to-date basis primarily due to the higher U.S./Canadian exchange rates. Increases in the U.S. per unit natural gas operating expenses for the third quarter and for the nine months ended September 30, 2004 compared to the same periods in 2003 were a result of 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 September 30)	North America 2004	North America 2004 vs 2003	North America 2003	Ecuador 2004	Ecuador 2004 vs 2003	Ecuador 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price [1]	**$ 31.49**	**55%**	$ 20.26	**$ 33.47**	**51%**	$ 22.13	**$ 40.88**	**46%**	$ 27.92
Expenses									
Production and mineral taxes	**0.34**	**143%**	(0.80)	**2.62**	**482%**	0.45	**–**	**–**	–
Transportation and selling	**1.42**	**125%**	0.63	**2.36**	**–**	2.36	**2.44**	**23%**	1.98
Operating	**5.42**	**–9%**	5.93	**4.35**	**–**	4.33	**9.98**	**52%**	6.55
Netback	**$ 24.31**		$ 14.50	**$ 24.14**		$ 14.99	**$ 28.46**		$ 19.39
Crude Oil Sales Volumes *(bbls per day)*	**142,506**	**–5%**	149,582	**74,846**	**88%**	39,807	**12,819**	**138%**	5,384

(1) Excludes realized commodity and currency hedge activities.

NGLs [1] *($ per barrel)*

(Three Months Ended September 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	**$ 33.46**	**42%**	$ 23.52	**$ 36.09**	**42%**	$ 25.50	**$ 25.82**	**38%**	$ 18.69
Expenses									
Production and mineral taxes	**–**	**–**	–	**4.05**	**53%**	2.64	**–**	**–**	–
Transportation and selling	**0.45**	**–22%**	0.58	**–**	**–**	–	**0.44**	**–78%**	2.01
Netback	**$ 33.01**		$ 22.94	**$ 32.04**		$ 22.86	**$ 25.38**		$ 16.68
NGLs Sales Volumes *(bbls per day)*	**12,804**	**–7%**	13,758	**14,363**	**51%**	9,530	**2,070**	**383%**	429

(1) NGLs results includes Condensate.

Crude Oil *($ per barrel)*

(Nine Months Ended September 30)	North America 2004	North America 2004 vs 2003	North America 2003	Ecuador 2004	Ecuador 2004 vs 2003	Ecuador 2003	United Kingdom 2004	United Kingdom 2004 vs 2003	United Kingdom 2003
Price [1]	**$ 27.70**	**22%**	$ 22.73	**$ 28.25**	**14%**	$ 24.68	**$ 35.16**	**22%**	$ 28.74
Expenses									
Production and mineral taxes	**0.35**	**–**	–	**1.93**	**9%**	1.77	**–**	**–**	–
Transportation and selling	**1.36**	**8%**	1.26	**2.30**	**–3%**	2.37	**2.04**	**–4%**	2.13
Operating	**5.29**	**–11%**	5.92	**4.17**	**–16%**	4.99	**7.08**	**61%**	4.41
Netback	**$ 20.70**		$ 15.55	**$ 19.85**		$ 15.55	**$ 26.04**		$ 22.20
Crude Oil Sales Volumes *(bbls per day)*	**143,172**	**3%**	139,187	**78,032**	**116%**	36,132	**15,855**	**105%**	7,737

(1) Excludes realized commodity and currency hedge activities.

NGLs [1] *($ per barrel)*

(Nine Months Ended September 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	**$ 29.65**	**24%**	$ 23.99	**$ 34.15**	**26%**	$ 27.07	**$ 23.79**	**15%**	$ 20.69
Expenses									
Production and mineral taxes	**–**	**–**	–	**3.77**	**108%**	1.81	**–**	**–**	–
Transportation and selling	**0.39**	**105%**	0.19	**–**	**–**	–	**1.19**	**–20%**	1.49
Netback	**$ 29.26**		$ 23.80	**$ 30.38**		$ 25.26	**$ 22.60**		$ 19.20
NGLs Sales Volumes *(bbls per day)*	**13,452**	**–8%**	14,591	**12,126**	**31%**	9,230	**2,035**	**180%**	726

(1) NGLs results includes Condensate.

Increases in the average crude oil price, excluding the impact of financial hedges, in the third quarter and first nine months 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 periods in 2003. Higher benchmark WTI crude oil prices of 45 percent in the quarter (27 percent year-to-date) for 2004 compared to the same periods in 2003 were partially offset by increased crude oil price differentials (up 49 percent in the third quarter and up 44 percent on a year-to-date basis) and a higher proportionate share of heavier blend oils in the product mix. Realized commodity and currency hedging losses on crude oil were approximately $221 million, or $9.28 per barrel of liquids in the third quarter of 2004 compared to a loss of approximately $44 million, or $2.18 per barrel of liquids in the third quarter 2003. On a year-to-date basis to September 30, realized commodity and currency hedging losses on crude oil were approximately $515 million, or $7.11 per barrel of liquids in 2004 compared to a loss of approximately $154 million, or $2.71 per barrel of liquids in 2003.

North American per unit production and mineral taxes increased in the third quarter and year-to-date primarily due to the impact of mineral tax amendments related to prior years that were recorded in the third quarter of 2003, which reduced mineral taxes by approximately $16 million or $0.42 per barrel on a year-to-date basis for 2003. This increase is offset slightly by the increased production weighting from properties that are not subject to production and mineral taxes combined with the disposition of several properties that were subject to production and mineral taxes. Per unit production and mineral taxes in Ecuador increased $2.17 per barrel in the third quarter of 2004 and $0.16 per barrel on a year-to-date basis over the same period 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.

Per unit crude oil transportation and selling costs in North America for the third quarter were higher by $0.79 per barrel over the same period of 2003. This is mainly 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 and a sales pipeline break at Pelican Lake resulting in additional trucking charges and repair costs during the third quarter of 2004. On a year-to-date basis, the per unit crude oil transportation and selling expenses in North America have increased $0.10 per barrel mainly due to the higher U.S./Canadian exchange rates. Per unit transportation and selling costs in Ecuador for the nine months ended September 30, 2004 decreased as a result of lower net realized costs of operations of the OCP Pipeline.

North American crude oil per unit operating costs have decreased $0.51 per barrel in the third quarter and $0.63 per barrel on a year-to-date basis compared to the same periods in 2003. This is due to the sale of Petrovera which had relatively higher operating costs, as well as lower per unit fixed costs due to increased volumes offset partially by the increased U.S./Canadian exchange rates. In Ecuador, a significant portion of operating expenses are fixed, resulting in lower per unit operating expenses as sales volumes increased for the nine months ended September 30, 2004 compared to the same period in 2003. The third quarter crude oil per unit operating expenses in Ecuador has increased slightly due to higher workover costs during the quarter. The increase in the U.K.'s third quarter and year-to-date 2004 crude oil operating expenses is primarily related to platform turnaround, higher maintenance and fuel expenses and the U.S./U.K. exchange rates.

MIDSTREAM & MARKETING OPERATIONS

Financial Results *($ millions)*

(Three Months Ended September 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	$ 158	–12%	$ 180	$ 731	22%	$ 601	$ 889	14%	$ 781
Expenses									
Transportation and selling	–	–	–	4	–64%	11	4	–64%	11
Operating	65	14%	57	12	71%	7	77	20%	64
Purchased product	88	–21%	112	712	23%	580	800	16%	692
Depreciation, depletion and amortization	8	14%	7	–	–	2	8	–11%	9
	$ (3)		$ 4	$ 3		$ 1	$ –		$ 5

(Nine Months Ended September 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	$ 881	36%	$ 649	$ 2,325	13%	$ 2,064	$ 3,206	18%	$ 2,713
Expenses									
Transportation and selling	–	–	–	20	–55%	44	20	–55%	44
Operating	192	2%	188	32	–40%	53	224	–7%	241
Purchased product	655	55%	423	2,254	14%	1,983	2,909	21%	2,406
Depreciation, depletion and amortization	58	222%	18	2	–33%	3	60	186%	21
	$ (24)		$ 20	$ 17		$ (19)	$ (7)		$ 1

Revenues and purchased product expense in Midstream & Marketing operations increased in the third quarter and on a nine-month basis compared to the same periods in 2003 due primarily to increases in commodity prices. Decreases in transportation and selling costs in the third quarter and year-to-date to September 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 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 year-to-date results between 2003 and 2004.

The increase in year-to-date 2004 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 September 30 2004	Three Months 2004 vs 2003	Three Months 2003	Nine Months Ended September 30 2004	Nine Months 2004 vs 2003	Nine Months 2003
Revenues, Net of Royalties	$ (501)	–	$ 1	$ (1,033)	–	$ 2
Expenses						
Operating	1	–	–	(4)	–	–
Depreciation, depletion and amortization	14	–	14	44	38%	32
Administration	43	5%	41	136	12%	121
Interest, net	103	45%	71	278	38%	202
Accretion of asset retirement obligation	8	60%	5	20	33%	15
Foreign exchange gains	(288)	1,340%	(20)	(209)	–52%	(436)
Stock-based compensation	5	–17%	6	14	17%	12
Gain on dispositions	–	–	–	(35)	–	–
Income tax expense	77	–62%	205	122	–64%	342

Corporate revenues, net of royalties in the third quarter of 2004 include approximately $500 million in unrealized mark-to-market losses related to commodity contracts. On a year-to-date basis, revenues, net of royalties include mark-to-market losses on commodity contracts of approximately $1,035 million. Other mark-to-market gains ($7 million year-to-date) on derivative financial instruments related to interest and electricity consumption are recorded in the interest, net and operating expense account respectively.

Depreciation, depletion and amortization include provisions for corporate assets such as computer equipment, office furniture and leasehold improvements. The increase in expense 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 third 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 $0.10 per BOE, at $0.60 per BOE, for the third quarter of 2004 ($0.65 per BOE year-to-date) compared with $0.70 per BOE for the third quarter in 2003 ($0.70 per BOE year-to-date). Lower per unit administrative expenses are primarily as a result of the increase in sales volumes.

The higher 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 gain of $288 million in the third quarter resulted from the change in the U.S./Canadian dollar period end exchange rate between June 30, 2004 and September 30, 2004 applied to U.S. dollar denominated debt issued in Canada as discussed previously in this MD&A. 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 third quarter of 2004 was 16 percent compared to 42 percent for the same period in 2003 and 12 percent compared to 16 percent for 2003 on a year-to-date basis as disclosed in Note 8 to the Interim Consolidated Financial Statements. 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 a 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.

EnCana sold oil and gas interests in a manner which resulted in the retention of certain associated tax basis resulting in a reduction to the tax provision for the third quarter in 2004 of $59 million and $162 million for year-to-date 2004.

Current income tax expense for the third quarter of 2004 was $124 million compared to $51 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 Alberta Energy Company Ltd. ("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

Capital Investment

($ millions)	Three Months Ended September 30 2004	2004 vs 2003	2003	Nine Months Ended September 30 2004	2004 vs 2003	2003
Upstream						
Canada	**$ 598**	**–33%**	$ 897	**$ 2,282**	**9%**	$ 2,096
United States	**325**	**16%**	279	**851**	**38%**	615
Ecuador	**53**	**–18%**	65	**163**	**–5%**	172
United Kingdom	**82**	**332%**	19	**290**	**544%**	45
Other Countries	**15**	**–**	15	**49**	**–22%**	63
Total Upstream	**$ 1,073**	**–16%**	$ 1,275	**$ 3,635**	**22%**	$ 2,991
Midstream & Marketing	**15**	**–74%**	58	**40**	**–74%**	154
Corporate	**10**	**43%**	7	**28**	**–26%**	38
Core Capital Expenditures	**$ 1,098**	**–18%**	$ 1,340	**$ 3,703**	**16%**	$ 3,183
Acquisition of Tom Brown, Inc. (1)	**–**	**–**	–	**2,335**	**–**	–
Acquisitions (2)	**49**	**–49%**	96	**189**	**–59%**	462
Dispositions (3)	**(940)**	**–**	–	**(1,359)**	**–**	(19)
Net Capital Expenditures (4)	**$ 207**	**–86%**	$ 1,436	**$ 4,868**	**34%**	$ 3,626

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

(2) Represents Corporate acquisitions and property acquisitions.

(3) The Petrovera acquisition of $253 million and subsequent disposition for $540 million has been included on a net basis in dispositions in the first quarter of 2004.

(4) Excludes discontinued operations.

The Company's core capital expenditures for the third quarter of 2004 were offset significantly by non-core asset dispositions that were discussed in the second quarter MD&A. The increase in Upstream core capital expenditures for the nine month period in 2004 compared to the same period in 2003 was primarily as a result of continued development of EnCana's North American resource play properties. Net capital expenditures increased approximately $1.2 billion for the nine months ended September 30, 2004 compared to the same period 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 partially offset by $1.4 billion in non-core asset dispositions. 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

The decreases in Upstream capital expenditures in the third quarter compared to the same quarter in 2003 is largely attributable to the September 2003 land acquisitions at Cutbank Ridge. The increase in Upstream capital expenditures on a year-to-date basis in 2004 compared to the same period in 2003 reflect increased drilling and development activities and the impact of the increased average U.S./Canadian dollar exchange rate on Canadian dollar denominated expenditures. On a year-to-date basis the change in the average U.S./Canadian dollar exchange rate resulted in an increase on Canadian dollar denominated capital expenditures of approximately $168 million. 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 Mamm Creek, Jonah and Texas. Capital expenditures in the U.K. primarily reflect activity related to the development of the Buzzard field. The Company drilled 3,998 net wells year-to-date September 30, 2004 compared to 4,113 net wells in the same period of 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 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

During the third quarter of 2004, the Company disposed of various non-core properties in North America for proceeds of approximately $940 million as disclosed previously in the second quarter MD&A. Total dispositions for the nine months ended September 30, 2004 are approximately $1.4 billion.

Other major acquisitions and divestitures completed and disclosed in the first two quarters of 2004 include the TBI acquisition for approximately $2.7 billion including $0.4 billion in acquired debt; the acquisition of additional interests in the Scott and Telford fields in the U.K. for approximately $112 million; and the disposition of the Company's interest in the Petrovera Partnership for approximately $287 million.

LIQUIDITY AND CAPITAL RESOURCES

EnCana's cash flow from continuing operations was $1,363 million for the three months ended September 30, 2004, up $390 million compared to the same period last year and on a year-to-date basis was $3,489 million for the period ended September 30, 2004, up $286 million compared to the same nine-month period in 2003. The increase in cash flows in the quarter and on a year-to-date basis were primarily due to increased revenues from the growth in sales volumes, higher commodity prices offset by higher realized commodity hedging losses, an increase in the current tax provision and an increase in the U.S./Canadian dollar exchange rate.

During the third quarter of 2004, long-term debt plus the current portion of long-term debt decreased $729 million compared to the previous quarter ended June 30, 2004 as a result of the dispositions and increase in cash flows. EnCana's net debt adjusted for working capital was $9,014 million as at September 30, 2004 compared with $5,931 million at December 31, 2003. Working capital was a deficit of $978 million at September 30, 2004 and included unrealized losses on mark-to-market accounting on derivatives of $674 million and a current tax payable of $526 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 and capital expenditures. As a result of these activities, long-term debt plus the current portion of long-term debt increased $2,211 million as at September 30, 2004 compared to the 2003 year-end.

Net debt to capitalization was 43 percent as of September 30, 2004, up from 34 percent at December 31, 2003, primarily as a result of the acquisition of TBI and the impact of mark-to-market accounting on derivatives. Management calculates this ratio for internal purposes to steward the Company's overall debt position as a measure of a company's financial strength.

EnCana's long term credit ratings were confirmed by all its credit rating agencies by the end of the third quarter. Standard & Poor's has affirmed an A- with a 'Negative Outlook', Dominion Bond Rating Services has affirmed an A(low) with a 'Negative Trend' and Moody's lowered EnCana's rating to Baa2 Stable. The agencies are expected to continue to monitor the Company's operating and financial performance through the year end.

On July 29, EnCana made a public offering in the United States for $250 million notes due in 2009 at 4.60 percent and $750 million notes due in 2034 at 6.50 percent. The proceeds from these issues were used primarily to repay existing bank and commercial paper indebtedness.

In September 2004, EnCana filed a multi-jurisdictional shelf prospectus whereby it may issue from time to time up to $2 billion of debt securities. This shelf prospectus replaced EnCana's previous $2 billion U.S. debt shelf prospectus which expired on September 22, 2004. No amounts have been issued under the new shelf prospectus.

On August 9, 2004, EnCana redeemed all of its 8.50% Unsecured Junior Subordinated Debentures due 2048, which had an aggregate principal amount of C$200 million, at par plus accrued interest. On September 30, 2004, EnCana redeemed all of its 9.50% Preferred Securities due 2048, which had an aggregate principal amount of $150 million, at par.

As at September 30, 2004, the Company had available unused committed bank credit facilities in the amount of $1,865 million.

In October 2003, EnCana received approval from Toronto Stock Exchange to continue to purchase, for cancellation, Common Shares under a Normal Course Issuer Bid (the "Bid"). Under the Bid, EnCana was 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 third quarter of 2004, EnCana did not purchase any of its shares 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. From the inception of this Bid in October 2003 through its expiry in October 2004, the Company had purchased for cancellation approximately 9.1 million Common Shares at an average price of C$51.56 per share.

On October 26, 2004 the Company received Toronto Stock Exchange approval for a new Normal Course Issuer Bid commencing October 29, 2004 for a twelve month period. Under this Bid, EnCana will be able to purchase for cancellation up to 23.1 million of its Common Shares, representing five percent of the approximately 462 million Common Shares outstanding as of October 15, 2004.

BUSINESS ENVIRONMENT

NATURAL GAS

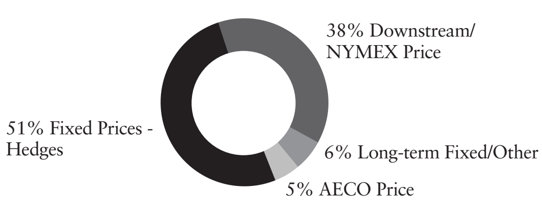
Natural Gas Price Benchmarks

	Three Months Ended September 30			Nine Months Ended September 30			Year Ended
(Average for the period)	**2004**	**2004 vs 2003**	2003	**2004**	**2004 vs 2003**	2003	2003
AECO Price *(C$/Mcf)*	**$ 6.66**	**6%**	$ 6.29	**$ 6.69**	**–5%**	$ 7.07	$ 6.70
NYMEX Price *($/MMBtu)*	**5.76**	**16%**	4.97	**5.81**	**3%**	5.66	5.39
Rockies (Opal) Price *($/MMBtu)*	**5.06**	**16%**	4.37	**5.02**	**22%**	4.10	4.12
AECO/NYMEX Basis Differential *($/MMBtu)*	**0.70**	**84%**	0.38	**0.78**	**5%**	0.74	0.65
Rockies/NYMEX Basis *($/MMBtu)*	**0.70**	**17%**	0.60	**0.80**	**–49%**	1.56	1.27

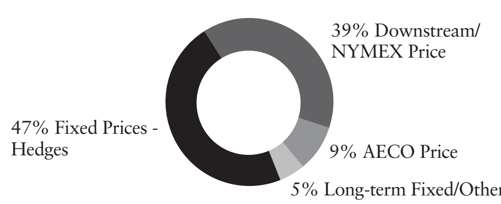
Concerns that North American natural gas supply will not be able to meet increasing demands and the influence of high crude oil prices have continued to result in historically high average NYMEX gas prices. Lower average AECO gas prices on a year-to-date basis in 2004 can be attributed to wider differentials from NYMEX in the third quarter combined with the appreciation of the U.S./Canadian dollar exchange rate. The increased AECO/NYMEX basis differential in the third quarter of 2004 compared to the third quarter of 2003 can be attributed to increased transportation differentials for the marginal sales volumes transported from Alberta to Eastern Canada.

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

2004



2003



CRUDE OIL

Crude Oil Price Benchmarks

(Average for the period US$/bbl)	Three Months Ended September 30 2004	2004 vs 2003	2003	Nine Months Ended September 30 2004	2004 vs 2003	2003	Year Ended 2003
WTI	**43.89**	**45%**	30.21	**39.21**	**27%**	30.94	30.99
Dated Brent	**41.54**	**46%**	28.41	**36.28**	**27%**	28.65	28.84
WTI/Bow River Differential	**12.09**	**49%**	8.12	**10.72**	**44%**	7.42	8.01
WTI/OCP NAPO Differential (Ecuador) [(1)]	**14.31**	**85%**	7.75	**12.71**	**64%**	7.75	8.06
WTI/Oriente Differential (Ecuador)	**11.63**	**118%**	5.34	**9.07**	**63%**	5.57	5.59

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

Continued increased demand in Asia and North America along with supply uncertainties in the Middle East as well as west Africa and recent damage to production platforms in the Gulf of Mexico has caused the WTI crude oil price to be significantly higher in the third quarter and on a year-to-date basis in 2004 when compared to the corresponding periods in 2003.

The Canadian WTI/Bow River heavy oil differential widened in the third quarter of 2004 compared to the third 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 third quarter of 2004 was 72 percent of WTI as compared to 73 percent in the third 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 third quarter and year-to-date 2004 increases in the Oriente differential compared to the same periods in 2003 are primarily related to the increase in the WTI price as well as wider U.S. Gulf Coast light to heavy product differentials.

U.S./CANADIAN DOLLAR EXCHANGE RATES

Foreign Exchange Benchmarks

(Average for the period)	Three Months Ended September 30 2004	2004 vs 2003	2003	Nine Months Ended September 30 2004	2004 vs 2003	2003	Year Ended 2003
U.S./Canadian Dollar Period-End Exchange Rate	**0.791**	**7%**	0.741	**0.791**	**7%**	0.741	0.774
U.S./Canadian Dollar Average Exchange Rate	**0.765**	**6%**	0.725	**0.753**	**7%**	0.701	0.716

The third quarter 2004 over third 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.

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 September 30, 2004, there were 462 million Common Shares outstanding compared to 465 million Common Shares outstanding at September 30, 2003 and 461 million Common Shares outstanding as at December 31, 2003. There were no Preferred Shares outstanding as at September 30, 2004 or September 30, 2003.

Employees and directors have been granted options to purchase Common Shares under various plans. During the third quarter of 2004, approximately 1.0 million Common Shares were issued (year-to-date approximately 6.9 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 did not repurchase any of its Common Shares during the third quarter. The Company has repurchased for cancellation 5.5 million Common Shares at an average price of C$55.37 in the first nine months of 2004 under a Normal Course Issuer Bid that was approved by 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 a discussion of the physical contracts.

Included in the long-term debt commitments, the Company had $2,446 million outstanding as at September 30, 2004 related to Banker's Acceptances, Commercial Paper and LIBOR loans that are supported by revolving credit facilities and term loan borrowings. Approximately $846 million of this amount is related to the bridge credit facility which was put in place to finance a portion of the TBI acquisition and is required to be reduced to $450 million principal outstanding by August 2005 and repaid in its entirety by May 2006. With respect to the balance of the outstanding revolving credit facilities and term loan borrowings of approximately $1,600 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 September 30, 2004, EnCana had entered into long-term, fixed price, physical contracts with a current delivery of approximately 48 MMcf per day with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 172 billion cubic feet at a weighted average price of $3.55 per Mcf. At September 30, 2004, these transactions had an unrealized loss of $177 million.

A subsidiary of the Company in Ecuador has a 40 percent economic interest in relation to Block 15 pursuant to a contract with a third party. The state oil company of Ecuador has formally notified the third party of a contractual dispute which is disclosed in Note 15 of the Interim Consolidated Financial Statements.

In addition to the above, the Company is proceeding with its arbitration related to value added tax and is in discussions related to certain income tax matters related to interest deductibility in Ecuador.

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. EnCana Corporation has been dismissed from the New York lawsuits, leaving only WD as a defendant. 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 September 30, 2004, approximately $242 million of these net losses were recognized. The timing of recognition of the remaining net gains of $7 million ($5 million after-tax) is described in Note 2 of the Interim Consolidated Financial Statements.

Changes in the fair value from June 30, 2004 to September 30, 2004 for these contracts, as well as all other outstanding hedge contracts, were marked-to-market and a $497 million loss ($321 million after-tax) was recognized in net earnings for the three months ended September 30, 2004. All unrealized losses on derivative instruments as at September 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.

COMMODITY PRICES

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. As a means of mitigating 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 the Company has entered into various financial instrument agreements for both natural gas and crude oil as disclosed in Note 14 of the Interim Consolidated Financial Statements. As at September 30, 2004, EnCana has fixed price physical contracts of approximately 48 MMcf per day and various physical Rockies natural gas basis contracts with varying terms and volumes through 2007. At September 30, 2004, these transactions had an unrealized loss of approximately $17 million.

OTHER RISKS

Other risks are partially mitigated through comprehensive insurance programs or managed by executing policies and standards that comply or exceed government regulations and industry standards. The Company also partially mitigates risks such as land access through communication and negotiation with individuals and communities in which it operates. Environmental risks such as the Kyoto Accord and similar initiatives in the U.S.A. remain unchanged as discussed in the 2003 year-end MD&A.

OUTLOOK

EnCana plans to focus primarily on exploitation of its North American resource plays to grow natural gas and crude oil production. The Company also has substantial assets in the Gulf of Mexico, Canadian East Coast, the U.K. central North Sea and Ecuador. The Company also plans to continue its focused, high-upside North American and international exploration programs.

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.

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.

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.

CURRENT INCOME TAXES

At the date hereof, based on First Call consensus commodity pricing, for the balance of the year and production and capital expenditure estimates based on the midpoint of public guidance, EnCana expects the 2004 provision for current income taxes will be within the guidance range of $675 million to $820 million.

LEGAL ADVISORY

NOTE REGARDING FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, certain statements throughout this 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 and beyond; the Company's plans to focus on exploitation of its resource plays and international exploitation projects to grow production of oil and natural gas; amounts which may be issued under the Company's multi-jurisdictional shelf prospectus program; the Company's projected capital investment levels for 2004 and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; 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; projected operating and administrative costs for 2004; the impact of the Kyoto Accord and similar initiatives in the U.S.A. on operating costs; projected tax rates and projected current taxes payable for 2004 and 2005 and the adequacy of the Company's provision for taxes; and rating agency monitoring and reviews which may occur in the future.

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 utilize a five year time frame for their specified period of time.

NOTE REGARDING CURRENCY, PROTOCOLS AND NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this MD&A and the Interim Consolidated Financial Statements and comparative information is shown on a U.S. 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 Operating Earnings per share-diluted 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.

References To EnCana

For convenience, references in this MD&A to "EnCana", the "Company", "we", "us" and "our" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

October 26, 2004

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

For the period ended September 30, 2004

(US$ millions, except per share amounts)		September 30 Three Months Ended 2004	2003	Nine Months Ended 2004	2003
REVENUES, NET OF ROYALTIES	*(Note 5)*				
Upstream		**$ 2,070**	$ 1,509	**$ 5,853**	$ 4,651
Midstream & Marketing		**889**	781	**3,206**	2,713
Corporate		**(501)**	1	**(1,033)**	2
		2,458	2,291	**8,026**	7,366
EXPENSES	*(Note 5)*				
Production and mineral taxes		**97**	33	**258**	131
Transportation and selling		**144**	125	**468**	375
Operating		**382**	322	**1,081**	960
Purchased product		**800**	692	**2,909**	2,406
Depreciation, depletion and amortization		**694**	525	**2,051**	1,497
Administrative		**43**	41	**136**	121
Interest, net		**103**	71	**278**	202
Accretion of asset retirement obligation	*(Note 10)*	**8**	5	**20**	15
Foreign exchange (gain)	*(Note 7)*	**(288)**	(20)	**(209)**	(436)
Stock-based compensation		**5**	6	**14**	12
Gain on dispositions	*(Note 4)*	**–**	–	**(35)**	–
		1,988	1,800	**6,971**	5,283
NET EARNINGS BEFORE INCOME TAX		**470**	491	**1,055**	2,083
Income tax expense	*(Note 8)*	**77**	205	**122**	342
NET EARNINGS FROM CONTINUING OPERATIONS		**393**	286	**933**	1,741
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 6)*	**–**	4	**–**	193
NET EARNINGS		**$ 393**	$ 290	**$ 933**	$ 1,934
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 13)*				
Basic		**$ 0.85**	$ 0.60	**$ 2.02**	$ 3.64
Diluted		**$ 0.84**	$ 0.60	**$ 2.00**	$ 3.60
NET EARNINGS PER COMMON SHARE	*(Note 13)*				
Basic		**$ 0.85**	$ 0.61	**$ 2.02**	$ 4.05
Diluted		**$ 0.84**	$ 0.61	**$ 2.00**	$ 4.00

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(US$ millions)		Nine Months Ended September 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		**933**	1,934
Dividends on Common Shares		**(137)**	(103)
Charges for Normal Course Issuer Bid	*(Note 11)*	**(126)**	(360)
RETAINED EARNINGS, END OF PERIOD		**$ 5,946**	$ 4,994

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

For the period ended September 30, 2004

(US$ millions)		As at September 30, 2004	As at December 31, 2003
ASSETS			
Current Assets			
Cash and cash equivalents		$ 107	$ 148
Accounts receivable and accrued revenues		2,066	1,367
Risk management	*(Note 14)*	84	–
Inventories		700	573
		2,957	2,088
Property, Plant and Equipment, net	*(Note 5)*	23,623	19,545
Investments and Other Assets		637	566
Risk Management	*(Note 14)*	46	–
Goodwill		2,410	1,911
	(Note 5)	$ 29,673	$ 24,110
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,059	$ 1,579
Risk management	*(Note 14)*	800	–
Income tax payable		526	65
Current portion of long-term debt	*(Note 9)*	550	287
		3,935	1,931
Long-Term Debt	*(Note 9)*	8,036	6,088
Other Liabilities		85	21
Risk Management	*(Note 14)*	332	–
Asset Retirement Obligation	*(Note 10)*	490	430
Future Income Taxes		4,712	4,362
		17,590	12,832
Shareholders' Equity			
Share capital	*(Note 11)*	5,412	5,305
Share options, net		21	55
Paid in surplus		53	18
Retained earnings		5,946	5,276
Foreign currency translation adjustment		651	624
		12,083	11,278
		$ 29,673	$ 24,110

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

For the period ended September 30, 2004

(US$ millions)		September 30 Three Months Ended 2004	2003	Nine Months Ended 2004	2003
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 393**	$ 286	**$ 933**	$ 1,741
Depreciation, depletion and amortization		**694**	525	**2,051**	1,497
Future income taxes	*(Note 8)*	**(47)**	154	**(437)**	325
Unrealized loss on risk management	*(Note 14)*	**497**	–	**1,028**	–
Unrealized foreign exchange (gain)	*(Note 7)*	**(193)**	(15)	**(122)**	(404)
Accretion of asset retirement obligation	*(Note 10)*	**8**	5	**20**	15
Gain on dispositions	*(Note 4)*	**–**	–	**(35)**	–
Other		**11**	18	**51**	29
Cash flow from continuing operations		**1,363**	973	**3,489**	3,203
Cash flow from discontinued operations		**–**	4	**–**	2
Cash flow		**1,363**	977	**3,489**	3,205
Net change in other assets and liabilities		**(25)**	(111)	**(71)**	(82)
Net change in non-cash working capital from continuing operations		**(276)**	159	**(103)**	200
Net change in non-cash working capital from discontinued operations		**–**	(3)	**–**	54
		1,062	1,022	**3,315**	3,377
INVESTING ACTIVITIES					
Business combination with Tom Brown, Inc.	*(Note 3)*	**–**	–	**(2,335)**	–
Capital expenditures	*(Note 5)*	**(1,147)**	(1,345)	**(3,892)**	(3,438)
Proceeds on disposal of assets		**941**	–	**1,072**	19
Dispositions (acquisitions)	*(Note 4)*	**(1)**	(91)	**287**	(207)
Equity investments	*(Note 4)*	**8**	(25)	**52**	(158)
Net change in investments and other		**(46)**	(41)	**(68)**	(68)
Net change in non-cash working capital from continuing operations		**(24)**	46	**(70)**	(112)
Discontinued operations		**–**	307	**–**	1,585
		(269)	(1,149)	**(4,954)**	(2,379)
FINANCING ACTIVITIES					
Net (repayment) issuance of revolving long-term debt		**(662)**	722	**(215)**	262
Issuance of long-term debt		**1,000**	–	**3,761**	–
Repayment of long-term debt		**(1,205)**	(71)	**(1,754)**	(142)
Issuance of common shares	*(Note 11)*	**30**	12	**184**	95
Purchase of common shares	*(Note 11)*	**–**	(560)	**(230)**	(682)
Dividends on common shares		**(45)**	(35)	**(137)**	(103)
Other		**(6)**	8	**(11)**	(5)
Discontinued operations		**–**	–	**–**	(282)
		(888)	76	**1,598**	(857)
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**–**	1	**–**	9
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		**(95)**	(52)	**(41)**	132
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**202**	300	**148**	116
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 107**	$ 248	**$ 107**	$ 248

See accompanying Notes to Consolidated Financial Statements.

For the period ended September 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 September 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 September 30, 2004, it is estimated that over the following 12 months, $42 million ($30 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 4	$ (64)
Total remaining to be recognized in 2004	$ (64)
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 in 2006 to 2008	$ 40
Total to be recognized	$ 7

NOTE 2
(continued)

At September 30, 2004, the remaining net deferred loss totalled $7 million of which $72 million was recorded in Accounts receivable and accrued revenues, $3 million in Investments and other assets, $30 million in Accounts payable and accrued liabilities and $52 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 sales were completed on July 30, 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 $287 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 $540 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. On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of $91 million. Savannah's operations are in Texas, USA. These purchases were accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the dates 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 September 30)*

	Upstream		Midstream & Marketing	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 2,070**	$ 1,509	**$ 889**	$ 781
Expenses				
Production and mineral taxes	**97**	33	**–**	–
Transportation and selling	**140**	114	**4**	11
Operating	**304**	258	**77**	64
Purchased product	**–**	–	**800**	692
Depreciation, depletion and amortization	**672**	502	**8**	9
Segment Income	**$ 857**	$ 602	**$ –**	$ 5

	Corporate		Consolidated	
	2004	2003	**2004**	2003
Revenues, Net of Royalties *	**$ (501)**	$ 1	**$ 2,458**	$ 2,291
Expenses				
Production and mineral taxes	**–**	–	**97**	33
Transportation and selling	**–**	–	**144**	125
Operating	**1**	–	**382**	322
Purchased product	**–**	–	**800**	692
Depreciation, depletion and amortization	**14**	14	**694**	525
Segment Income	**$ (516)**	$ (13)	**341**	594
Administrative			**43**	41
Interest, net			**103**	71
Accretion of asset retirement obligation			**8**	5
Foreign exchange (gain)			**(288)**	(20)
Stock-based compensation			**5**	6
Gain on dispositions			**–**	–
			(129)	103
Net Earnings Before Income Tax			**470**	491
Income tax expense			**77**	205
Net Earnings from Continuing Operations			**$ 393**	$ 286

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

NOTE 5
(continued)

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

UPSTREAM	Canada		United States		Ecuador	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 1,283**	$ 1,072	**$ 512**	$ 281	**$ 159**	$ 81
Expenses						
Production and mineral taxes	**23**	4	**56**	28	**18**	1
Transportation and selling	**91**	80	**23**	22	**16**	9
Operating	**170**	170	**32**	18	**30**	16
Depreciation, depletion and amortization	**445**	377	**131**	78	**63**	33
Segment Income	**$ 554**	$ 441	**$ 270**	$ 135	**$ 32**	$ 22

	U.K. North Sea		Other		Total Upstream	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 50**	$ 17	**$ 66**	$ 58	**$ 2,070**	$ 1,509
Expenses						
Production and mineral taxes	**–**	–	**–**	–	**97**	33
Transportation and selling	**10**	3	**–**	–	**140**	114
Operating	**12**	3	**60**	51	**304**	258
Depreciation, depletion and amortization	**26**	12	**7**	2	**672**	502
Segment Income	**$ 2**	$ (1)	**$ (1)**	$ 5	**$ 857**	$ 602

MIDSTREAM & MARKETING	Midstream		Marketing		Total Midstream & Marketing	
	2004	2003	**2004**	2003	**2004**	2003
Revenues	**$ 158**	$ 180	**$ 731**	$ 601	**$ 889**	$ 781
Expenses						
Transportation and selling	**–**	–	**4**	11	**4**	11
Operating	**65**	57	**12**	7	**77**	64
Purchased product	**88**	112	**712**	580	**800**	692
Depreciation, depletion and amortization	**8**	7	**–**	2	**8**	9
Segment Income	**$ (3)**	$ 4	**$ 3**	$ 1	**$ –**	$ 5

NOTE 5
(continued)

Upstream Geographic and Product Information *(For the three months ended September 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	**$ 970**	$ 806	**$ 462**	$ 259	**$ 10**	$ 2	**$ 1,442**	$ 1,067
Expenses								
Production and mineral taxes	**18**	15	**51**	25	**–**	–	**69**	40
Transportation and selling	**72**	71	**23**	22	**7**	1	**102**	94
Operating	**99**	89	**32**	18	**–**	–	**131**	107
Operating Cash Flow	**$ 781**	$ 631	**$ 356**	$ 194	**$ 3**	$ 1	**$ 1,140**	$ 826

OIL & NGLs

	Oil & NGLs					
	Canada		United States		Ecuador	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 313**	$ 266	**$ 50**	$ 22	**$ 159**	$ 81
Expenses						
Production and mineral taxes	**5**	(11)	**5**	3	**18**	1
Transportation and selling	**19**	9	**–**	–	**16**	9
Operating	**71**	81	**–**	–	**30**	16
Operating Cash Flow	**$ 218**	$ 187	**$ 45**	$ 19	**$ 95**	$ 55

	Oil & NGLs			
	U.K. North Sea		Total	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 40**	$ 15	**$ 562**	$ 384
Expenses				
Production and mineral taxes	**–**	–	**28**	(7)
Transportation and selling	**3**	2	**38**	20
Operating	**12**	3	**113**	100
Operating Cash Flow	**$ 25**	$ 10	**$ 383**	$ 271

OTHER & TOTAL UPSTREAM

	Other		Total Upstream	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 66**	$ 58	**$ 2,070**	$ 1,509
Expenses				
Production and mineral taxes	**–**	–	**97**	33
Transportation and selling	**–**	–	**140**	114
Operating	**60**	51	**304**	258
Operating Cash Flow	**$ 6**	$ 7	**$ 1,529**	$ 1,104

NOTE 5
(continued)

Results of Operations *(For the nine months ended September 30)*

	Upstream		Midstream & Marketing	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 5,853**	$ 4,651	**$ 3,206**	$ 2,713
Expenses				
Production and mineral taxes	**258**	131	**–**	–
Transportation and selling	**448**	331	**20**	44
Operating	**861**	719	**224**	241
Purchased product	**–**	–	**2,909**	2,406
Depreciation, depletion and amortization	**1,947**	1,444	**60**	21
Segment Income	**$ 2,339**	$ 2,026	**$ (7)**	$ 1

	Corporate		Consolidated	
	2004	2003	**2004**	2003
Revenues, Net of Royalties *	**$ (1,033)**	$ 2	**$ 8,026**	$ 7,366
Expenses				
Production and mineral taxes	**–**	–	**258**	131
Transportation and selling	**–**	–	**468**	375
Operating	**(4)**	–	**1,081**	960
Purchased product	**–**	–	**2,909**	2,406
Depreciation, depletion and amortization	**44**	32	**2,051**	1,497
Segment Income	**$ (1,073)**	$ (30)	**1,259**	1,997
Administrative			**136**	121
Interest, net			**278**	202
Accretion of asset retirement obligation			**20**	15
Foreign exchange (gain)			**(209)**	(436)
Stock-based compensation			**14**	12
Gain on dispositions			**(35)**	–
			204	(86)
Net Earnings Before Income Tax			**1,055**	2,083
Income tax expense			**122**	342
Net Earnings from Continuing Operations			**$ 933**	$ 1,741

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

NOTE 5
(continued)

Results of Operations *(For the nine months ended September 30)*

UPSTREAM	Canada		United States		Ecuador	
	2004	2003	**2004**	2003	**2004**	2003
Revenues, Net of Royalties	**$ 3,770**	$ 3,343	**$ 1,313**	$ 845	**$ 432**	$ 243
Expenses						
Production and mineral taxes	**61**	33	**155**	81	**42**	17
Transportation and selling	**277**	241	**93**	56	**49**	24
Operating	**505**	482	**80**	43	**89**	50
Depreciation, depletion and amortization	**1,296**	1,089	**330**	211	**197**	87
Segment Income	**$ 1,631**	$ 1,498	**$ 655**	$ 454	**$ 55**	$ 65

Transportation and selling for the United States includes a one-time payment of $21 million made in Q2 2004 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	**$ 168**	$ 73	**$ 170**	$ 147	**$ 5,853**	$ 4,651
Expenses						
Production and mineral taxes	**–**	–	**–**	–	**258**	131
Transportation and selling	**29**	10	**–**	–	**448**	331
Operating	**32**	10	**155**	134	**861**	719
Depreciation, depletion and amortization	**93**	53	**31**	4	**1,947**	1,444
Segment Income	**$ 14**	$ –	**$ (16)**	$ 9	**$ 2,339**	$ 2,026

MIDSTREAM & MARKETING	Midstream		Marketing		Total Midstream & Marketing	
	2004	2003	**2004**	2003	**2004**	2003
Revenues	**$ 881**	$ 649	**$ 2,325**	$ 2,064	**$ 3,206**	$ 2,713
Expenses						
Transportation and selling	**–**	–	**20**	44	**20**	44
Operating	**192**	188	**32**	53	**224**	241
Purchased product	**655**	423	**2,254**	1,983	**2,909**	2,406
Depreciation, depletion and amortization	**58**	18	**2**	3	**60**	21
Segment Income	**$ (24)**	$ 20	**$ 17**	$ (19)	**$ (7)**	$ 1

Midstream Depreciation, depletion and amortization includes a $35 million impairment charge made in Q2 2004 on the Company's interest in Oleoducto Trasandino in Argentina and Chile.

NOTE 5
(continued)

Upstream Geographic and Product Information *(For the nine months ended September 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	**$ 2,887**	$ 2,534	**$ 1,198**	$ 776	**$ 36**	$ 8	**$ 4,121**	$ 3,318
Expenses								
Production and mineral taxes	**46**	33	**142**	77	**–**	–	**188**	110
Transportation and selling	**222**	193	**93**	56	**19**	6	**334**	255
Operating	**297**	258	**80**	43	**–**	–	**377**	301
Operating Cash Flow	**$ 2,322**	$ 2,050	**$ 883**	$ 600	**$ 17**	$ 2	**$ 3,222**	$ 2,652

Transportation and selling for the United States includes a one-time payment of $21 million made in Q2 2004 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	**$ 883**	$ 809	**$ 115**	$ 69	**$ 432**	$ 243
Expenses						
Production and mineral taxes	**15**	–	**13**	4	**42**	17
Transportation and selling	**55**	48	**–**	–	**49**	24
Operating	**208**	224	**–**	–	**89**	50
Operating Cash Flow	**$ 605**	$ 537	**$ 102**	$ 65	**$ 252**	$ 152

	Oil & NGLs			
	U.K. North Sea		Total	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 132**	$ 65	**$ 1,562**	$ 1,186
Expenses				
Production and mineral taxes	**–**	–	**70**	21
Transportation and selling	**10**	4	**114**	76
Operating	**32**	10	**329**	284
Operating Cash Flow	**$ 90**	$ 51	**$ 1,049**	$ 805

OTHER & TOTAL UPSTREAM	Other		Total Upstream	
	2004	2003	**2004**	2003
Revenues, Net of Royalties	**$ 170**	$ 147	**$ 5,853**	$ 4,651
Expenses				
Production and mineral taxes	**–**	–	**258**	131
Transportation and selling	**–**	–	**448**	331
Operating	**155**	134	**861**	719
Operating Cash Flow	**$ 15**	$ 13	**$ 4,286**	$ 3,470

NOTE 5
(continued)

Capital Expenditures

	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
Upstream				
Canada	**$ 634**	$ 901	**$ 2,337**	$ 2,287
United States	**328**	280	**854**	626
Ecuador	**53**	65	**163**	172
United Kingdom	**92**	19	**421**	45
Other Countries	**15**	15	**49**	63
	1,122	1,280	**3,824**	3,193
Midstream & Marketing	**15**	58	**40**	207
Corporate	**10**	7	**28**	38
Total	**$ 1,147**	$ 1,345	**$ 3,892**	$ 3,438

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment As at September 30, 2004	Property, Plant and Equipment As at December 31, 2003	Total Assets As at September 30, 2004	Total Assets As at December 31, 2003
Upstream	**$ 22,590**	$ 18,532	**$ 27,030**	$ 21,742
Midstream & Marketing	**808**	784	**1,977**	1,879
Corporate	**225**	229	**666**	489
Total	**$ 23,623**	$ 19,545	**$ 29,673**	$ 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 September 30, 2003	Syncrude	Midstream – Pipelines	Total
Revenues, Net of Royalties	$ 8	$ –	$ 8
Expenses			
Transportation and selling	–	–	–
Operating	4	–	4
Depreciation, depletion and amortization	1	–	1
Gain on discontinuance	–	–	–
	5	–	5
Net Earnings Before Income Tax	3	–	3
Income tax expense	(1)	–	(1)
Net Earnings from Discontinued Operations	$ 4	$ –	$ 4

NOTE 6
(continued)

Consolidated Statement of Earnings

For the nine months ended September 30, 2003	Syncrude	Midstream – Pipelines	Total
Revenues, Net of Royalties	$ 87	$ –	$ 87
Expenses			
Transportation and selling	2	–	2
Operating	46	–	46
Depreciation, depletion and amortization	7	–	7
Gain on discontinuance	–	(220)	(220)
	55	(220)	(165)
Net Earnings Before Income Tax	32	220	252
Income tax expense	8	51	59
Net Earnings from Discontinued Operations	$ 24	$ 169	$ 193

NOTE 7

FOREIGN EXCHANGE (GAIN)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	**2004**	2003
Unrealized Foreign Exchange (Gain) on Translation of U.S. Dollar Debt Issued in Canada	**$ (193)**	$ (15)	**$ (122)**	$ (404)
Realized Foreign Exchange (Gain)	**(95)**	(5)	**(87)**	(32)
	$ (288)	$ (20)	**$ (209)**	$ (436)

NOTE 8

INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	**2004**	2003
Current				
Canada	**$ 76**	$ 31	**$ 441**	$ (18)
United States	**3**	10	**18**	10
Ecuador	**44**	8	**98**	21
United Kingdom	**–**	1	**–**	3
Other	**1**	1	**2**	1
Total Current Tax	**124**	51	**559**	17
Future	**(47)**	154	**(328)**	687
Future Tax Rate Reductions *	**–**	–	**(109)**	(362)
Total Future Tax	**(47)**	154	**(437)**	325
	$ 77	$ 205	**$ 122**	$ 342

* 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 September 30,		Nine Months Ended September 30,	
	2004	2003	**2004**	2003
Net Earnings Before Income Tax	**$ 470**	$ 491	**$ 1,055**	$ 2,083
Canadian Statutory Rate	**39.1%**	41.0%	**39.1%**	41.0%
Expected Income Taxes	**184**	201	**413**	853
Effect on Taxes Resulting from:				
Non-deductible Canadian crown payments	**51**	44	**154**	176
Canadian resource allowance	**(57)**	(56)	**(173)**	(206)
Canadian resource allowance on unrealized risk management losses	**13**	–	**40**	–
Statutory and other rate differences	**(19)**	1	**(49)**	(23)
Effect of tax rate changes	**–**	–	**(109)**	(362)
Non-taxable capital gains	**(55)**	(1)	**(41)**	(71)
Previously unrecognized capital losses	**(5)**	(71)	**10**	(71)
Tax basis retained on dispositions	**(59)**	–	**(162)**	–
Large corporations tax	**6**	8	**13**	25
Other	**18**	79	**26**	21
	$ 77	$ 205	**$ 122**	$ 342
Effective Tax Rate	**16.4%**	41.8%	**11.6%**	16.4%

NOTE 9

LONG-TERM DEBT

	As at September 30, 2004	As at December 31, 2003
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 1,509**	$ 1,425
Unsecured notes and debentures	**1,325**	1,335
Preferred securities	**–**	252
	2,834	3,012
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**965**	417
Unsecured notes and debentures	**4,716**	2,713
Preferred securities	**–**	150
	5,681	3,280
Increase in Value of Debt Acquired *	**71**	83
Current Portion of Long-Term Debt	**(550)**	(287)
	$ 8,036	$ 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 22 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. The facility size has been reduced to an outstanding amount of $846 million as at September 30, 2004. The remaining facility amount is to be reduced to $450 million by August 20, 2005 and to zero on May 20, 2006.

During the quarter, the Company completed an issue of notes under its shelf prospectus. The US$250 million notes are due in 2009 and bear interest at 4.60%. The US$750 million notes are due in 2034 and bear interest at 6.50%. The proceeds from the note issue were used to repay bank and commercial paper indebtedness. In addition, the Company also redeemed, at par value, the C$200 million 8.50% Preferred Securities and the US$150 million 9.50% Preferred Securities.

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 September 30, 2004	As at December 31, 2003
Asset Retirement Obligation, Beginning of Year	**$ 430**	$ 309
Liabilities Incurred	**64**	64
Liabilities Settled	**(9)**	(23)
Liabilities Disposed	**(35)**	–
Accretion Expense	**20**	19
Other	**20**	61
Asset Retirement Obligation, End of Period	**$ 490**	$ 430

NOTE 11 SHARE CAPITAL

	September 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	**6.9**	**184**	5.5	114
Shares Repurchased	**(5.5)**	**(77)**	(23.8)	(320)
Common Shares Outstanding, End of Period	**462.0**	**$ 5,412**	460.6	$ 5,305

To September 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 September 30, 2004:

	Stock Options *(millions)*	Weighted Average Exercise Price *(C$)*
Outstanding, Beginning of Year	**28.8**	**43.13**
Exercised	**(6.9)**	**35.46**
Forfeited	**(0.6)**	**47.30**
Outstanding, End of Period	**21.3**	**45.42**
Exercisable, End of Period	**13.4**	**43.90**

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	0.4	0.6	18.62	0.4	18.62
20.00 to 24.99	0.8	1.1	22.53	0.8	22.53
25.00 to 29.99	0.7	1.2	26.23	0.7	26.23
30.00 to 43.99	0.7	1.7	39.87	0.6	39.41
44.00 to 53.00	18.7	3.1	47.96	10.9	47.87
	21.3	2.4	45.42	13.4	43.90

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. Stock options granted in 2004 have an associated Tandem Share Appreciation Right attached. 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 September 30, 2004 would have been $384 million; $0.83 per common share – basic; $0.82 per common share – diluted (2003 – $281 million; $0.59 per common share – basic; $0.59 per common share – diluted). Pro forma Net Earnings and Net Earnings per Common Share for the nine months ended September 30, 2004 would have been $906 million; $1.97 per common share – basic; $1.94 per common share – diluted (2003 – $1,908 million; $3.99 per common share – basic; $3.94 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:

	September 30, 2003
Weighted Average Fair Value of Options Granted *(C$)*	$ 12.21
Risk Free Interest Rate	3.89%
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 September 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 September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
Current Service Cost	$ 1	$ 2	$ 4	$ 5
Interest Cost	3	3	9	9
Expected Return on Plan Assets	(2)	(2)	(8)	(7)
Amortization of Net Actuarial Loss	1	1	3	3
Amortization of Transitional Obligation	–	(1)	(1)	(2)
Amortization of Past Service Cost	–	–	1	1
Expense for Defined Contribution Plan	3	3	10	9
Net Benefit Plan Expense	$ 6	$ 6	$ 18	$ 18

At September 30, 2004, $17 million has been contributed to the pension plans and the Company expects to make no additional contributions during the remainder of 2004.

NOTE 12
(continued)

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

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

	Outstanding SAR's	Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	1,175,070	35.87
Exercised	(497,785)	35.15
Forfeited	(11,040)	29.25
Outstanding, End of Period	666,245	36.52
Exercisable, End of Period	666,245	36.52
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	753,417	28.98
Exercised	(279,258)	29.27
Forfeited	(1,472)	24.08
Outstanding, End of Period	472,687	28.82
Exercisable, End of Period	472,687	28.82

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

	Outstanding Tandem SAR's	Weighted Average Exercise Price *(C$)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	–	–
Granted	976,650	54.58
Forfeited	(77,500)	54.24
Outstanding, End of Period	899,150	54.61
Exercisable, End of Period	–	–

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

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

	Outstanding DSU's	Weighted Average Exercise Price *(C$)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	319,250	48.68
Granted, Directors	58,145	53.69
Granted, Senior Executives	1,686	57.54
Outstanding, End of Period	379,081	49.49
Exercisable, End of Period	297,874	51.82

NOTE 12
(continued)

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

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

	Outstanding PSU's	Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**126,283**	**46.52**
Granted	**1,687,571**	**53.97**
Forfeited	(70,540)	**53.17**
Outstanding, End of Period	**1,743,314**	**53.46**
Exercisable, End of Period	–	–
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	–	–
Granted	**249,830**	**41.12**
Forfeited	**(19,547)**	**41.12**
Outstanding, End of Period	**230,283**	**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				Nine Months Ended	
	March 31,	June 30,	September 30,		September 30,	
(millions)	2004	2004	**2004**	2003	**2004**	2003
Weighted Average Common Shares Outstanding – Basic	460.9	460.3	**461.7**	473.4	**461.0**	478.0
Effect of Dilutive Securities	6.2	5.2	**4.5**	4.5	**6.1**	5.7
Weighted Average Common Shares Outstanding – Diluted	467.1	465.5	**466.2**	477.9	**467.1**	483.7

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.

NOTE 14
(continued)

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2004 to September 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., Net of Amortization		5	–	(5)	–
Change in Fair Value of Contracts Still Outstanding at September 30, 2004		–	–	(328)	**(328)**
Fair Value of Contracts Realized During the Period		–	(242)	242	–
Fair Value of Contracts Entered into During the Period		–	–	(700)	**(700)**
Fair Value of Contracts Outstanding		$ 5	$ (7)	$ (1,026)	**$ (1,028)**
Premiums Paid on Collars and Options				24	
Fair Value of Contracts Outstanding and Premiums Paid, End of Period				$ (1,002)	

The total realized loss recognized in net earnings for the quarter and year-to-date ended September 30, 2004 was $256 million ($173 million, net of tax) and $664 million ($449 million, net of tax), respectively.

At September 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 September 30, 2004
Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	**$ 72**
Investments and other assets	**3**
Accounts payable and accrued liabilities	**30**
Other liabilities	**52**
Total Net Deferred Loss	**$ (7)**
Risk Management	
Current asset	**$ 84**
Long-term asset	**46**
Current liability	**800**
Long-term liability	**332**
Total Net Risk Management Liability	**$ (1,002)**

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

	As at September 30, 2004
Commodity Price Risk	
Natural gas	**$ (500)**
Crude oil	**(537)**
Power	**6**
Foreign Currency Risk	–
Interest Rate Risk	**29**
	$ (1,002)

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 September 30, 2004.

NOTE 14
(continued)

Natural Gas

At September 30, 2004, the Company's gas risk management activities for financial contracts had an unrealized loss of $(495) million and a fair market value position of $(500) million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
Fixed AECO price	454	2004	6.19	C$/Mcf	$ (34)
NYMEX Fixed price	702	2004	5.15	US$/Mcf	(96)
Colorado Interstate Gas (CIG)	52	2004	5.55	US$/Mcf	(1)
Other (1)	162	2004	5.57	US$/Mcf	(10)
NYMEX Fixed Price	180	2005	5.66	US$/Mcf	(79)
Colorado Interstate Gas (CIG)	113	2005	4.87	US$/Mcf	(51)
Other (1)	110	2005	5.21	US$/Mcf	(50)
NYMEX Fixed Price	525	2006	5.66	US$/Mcf	(99)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(35)
Other (1)	171	2006	4.85	US$/Mcf	(60)
Collars and Other Options					
AECO Collars	73	2004	5.36 – 7.54	C$/Mcf	(3)
NYMEX Collars	24	2004	4.45 – 5.95	US$/Mcf	(1)
Purchased NYMEX Put Options	33	2004	5.00	US$/Mcf	–
Other (2)	57	2004	4.31- 6.53	US$/Mcf	(1)
Purchased NYMEX Put Options	474	2005	5.00	US$/Mcf	(17)
Other (2)	5	2005	4.56 – 7.23	US$/Mcf	(2)
NYMEX 3-Way Call Spread	180	2005	5.00/6.69/7.69	US$/Mcf	(28)
Basis Contracts					
Fixed NYMEX to AECO Basis	325	2004	(0.54)	US$/Mcf	9
Fixed NYMEX to Rockies Basis	303	2004	(0.50)	US$/Mcf	12
Other (3)	240	2004	(0.39)	US$/Mcf	3
Fixed NYMEX to AECO Basis	877	2005	(0.66)	US$/Mcf	38
Fixed NYMEX to Rockies Basis	268	2005	(0.49)	US$/Mcf	21
Other (3)	442	2005	(0.47)	US$/Mcf	2
Fixed NYMEX to AECO Basis	464	2006-2008	(0.65)	US$/Mcf	22
Fixed NYMEX to Rockies Basis	249	2006-2008	(0.57)	US$/Mcf	6
Fixed NYMEX to CIG Basis	150	2006-2008	(0.76)	US$/Mcf	(10)
Fixed Rockies to CIG Basis	31	2006-2008	(0.10)	US$/Mcf	–
Other (3)	132	2006	(0.45)	US$/Mcf	(1)
Purchase Contracts					
Fixed Price Contracts					
Waha Purchase	30	2004	6.18	US$/Mcf	(1)
Waha Purchase	27	2005	5.90	US$/Mcf	5
Waha Purchase	23	2006	5.32	US$/Mcf	4
Premiums Paid on 3-Way Call Spread					3
Total Natural Gas Financial Positions					(454)
Gas Storage Financial Positions					(49)
Gas Marketing Financial Positions (4)					3
Total Fair Value Positions					(500)
Contracts Acquired					5
Total Unrealized Loss on Financial Contracts					$ (495)

(1) Other Fixed Price Contracts relate to various price points at Chicago, San Juan, Waha, Houston Ship Channel (HSC), Mid-Continent, Rockies and Texas Oklahoma.

(2) Other Collars and Other Options relate to collars at Permian, San Juan, Waha, Colorado Interstate Gas (CIG), HSC, Mid-Continent, Rockies and Texas Oklahoma.

(3) Other Basis Contracts relate to Chicago, San Juan, CIG, HSC, Mid-Continent, Waha and Ventura.

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

NOTE 14
(continued)

Crude Oil

At September 30, 2004, the Company's oil risk management activities for all financial contracts had an unrealized loss of $(558) million and a fair market value position of $(537) 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	$ (148)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(133)
Unwind WTI NYMEX Fixed Price	(9,000)	2004	39.22	8
Purchased WTI NYMEX Call Options	(111,000)	2004	46.64	29
Fixed WTI NYMEX Price	45,000	2005	28.41	(260)
Costless 3-Way Put Spread	10,000	2005	20.00/25.00/28.78	(56)
Unwind WTI NYMEX Fixed Price	(4,500)	2005	35.90	14
Purchased WTI NYMEX Call Options	(38,000)	2005	49.76	18
Fixed WTI NYMEX Price	15,000	2006	34.56	(27)
Purchased WTI NYMEX Put Options	17,000	2006	26.59	(3)
				(558)
Crude Oil Marketing Financial Positions (1)				–
Total Unrealized Loss on Financial Contracts				(558)
Premiums Paid on Call Options				21
Total Fair Value Positions				$ (537)

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

NOTE 15

COMMITMENTS AND CONTINGENCIES

Ecuador

In Ecuador, a subsidiary of the Company has a 40 percent economic interest in relation to Block 15 pursuant to a contract with a subsidiary of Occidental Petroleum Corporation. During the third quarter, Occidental Petroleum Corporation filed a Form 8-K indicating that its subsidiary had received formal notification from Petroecuador, the state oil company of Ecuador, initiating proceedings to determine if the subsidiary had violated the Hydrocarbons Law and its Participation Contract for Block 15 with Petroecuador and whether such violations constitute grounds for terminating the Participation Contract.

In its Form 8-K, Occidental Petroleum Corporation indicated that it believes it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties.

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 Q3	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Cash Flow	**3,489**	**1,363**	1,131	995	4,459	1,254	977	1,007	1,221
Per share - Basic	**7.57**	**2.95**	2.46	2.16	9.41	2.71	2.06	2.10	2.54
- Diluted	**7.47**	**2.92**	2.43	2.13	9.30	2.69	2.04	2.08	2.52
Net Earnings	**933**	**393**	250	290	2,360	426	290	807	837
Per share - Basic	**2.02**	**0.85**	0.54	0.63	4.98	0.92	0.61	1.68	1.74
- Diluted	**2.00**	**0.84**	0.54	0.62	4.92	0.91	0.61	1.67	1.73
Net Earnings from Continuing Operations	**933**	**393**	250	290	2,167	426	286	805	650
Per share - Basic	**2.02**	**0.85**	0.54	0.63	4.57	0.92	0.60	1.67	1.35
- Diluted	**2.00**	**0.84**	0.54	0.62	4.52	0.91	0.60	1.66	1.34
Operating Earnings *	**1,403**	**559**	379	465	1,375	316	274	275	510
Per share – Diluted	**3.00**	**1.20**	0.81	1.00	2.87	0.68	0.57	0.56	1.05
Foreign Exchange Rates *(US$ per C$1)*									
Average	**0.753**	**0.765**	0.736	0.759	0.716	0.760	0.725	0.715	0.662
Period end	**0.791**	**0.791**	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 Q3	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Common Shares Outstanding *(millions)*									
Period end	**462.0**	**462.0**	461.0	459.8	460.6	460.6	465.0	479.9	480.6
Average – Basic	**461.0**	**461.7**	460.3	460.9	474.1	462.3	473.4	480.6	479.9
Average – Diluted	**467.1**	**466.2**	465.5	467.1	479.7	465.9	477.9	484.4	484.3
Price Range *($ per share)*									
TSX – *C$*									
High	**60.60**	**60.60**	59.73	59.27	53.55	52.25	52.79	53.55	50.00
Low	**51.00**	**52.30**	52.99	51.00	44.60	44.60	47.49	45.26	45.74
Close	**58.35**	**58.35**	57.62	56.69	51.00	51.00	48.90	51.70	47.75
NYSE – *US$*									
High	**46.92**	**46.92**	44.73	44.25	40.08	40.08	38.34	39.63	33.50
Low	**38.05**	**39.95**	38.05	38.36	29.91	33.46	34.00	30.45	29.91
Close	**46.30**	**46.30**	43.16	43.12	39.44	39.44	36.38	38.37	32.36
Share Volume Traded *(millions)*	**364.7**	**114.7**	121.2	128.8	476.4	141.1	117.9	107.2	110.2
Share Value Traded *(US$ millions weekly average)*	**387.3**	**364.8**	392.9	403.7	317.6	397.3	321.5	289.9	266.7

Financial Metrics	
Debt to Capitalization	**43%**
Debt to EBITDA	**2.1x**
Return on Capital Employed	**8%**
Return on Common Equity	**12%**

Financial Statistics (continued)

Net Capital Investment *(US$ millions)*	2004	2003
Upstream		
Canada	**$ 2,282**	$ 2,096
United States	**851**	615
Ecuador	**163**	172
United Kingdom	**290**	45
Other Countries	**49**	63
	3,635	2,991
Midstream & Marketing	**40**	154
Corporate	**28**	38
Core Capital	**3,703**	3,183
Acquisitions		
Upstream		
Property		
Canada	**55**	191
United States	**3**	11
United Kingdom	**131**	–
Corporate		
Vintage	**–**	116
Savannah	**–**	91
Petrovera	**253**	–
Tom Brown, Inc. *	**2,335**	–
Midstream & Marketing	**–**	53
Dispositions		
Upstream		
Property		
Canada	**(797)**	(19)
United States	**(274)**	–
Corporate		
Petrovera	**(540)**	–
Midstream & Marketing	**(1)**	–
Net Acquisition and Disposition activity	**1,165**	443
Net Capital Investment – Continuing Operations	**4,868**	3,626
Discontinued Operations	**–**	(1,585)
Total Net Capital Investment	**$ 4,868**	$ 2,041

* Net cash consideration excluding debt acquired of $406 million.

Operating Statistics – After Royalties

	2004				2003				
Sales Volumes	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*									
Canada									
Production	**2,105**	**2,138**	2,177	2,000	1,935	2,008	1,914	1,899	1,922
Inventory withdrawal	**–**	**–**	–	–	30	–	–	–	120
Canada Sales *	**2,105**	**2,138**	2,177	2,000	1,965	2,008	1,914	1,899	2,042
United States	**823**	**958**	824	684	588	654	604	558	534
United Kingdom	**32**	**32**	36	28	13	20	7	12	13
	2,960	**3,128**	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	**57,388**	**52,824**	64,448	54,940	54,459	56,585	54,597	52,733	53,890
Heavy Oil	**85,784**	**89,682**	79,899	87,729	87,867	95,059	94,985	82,001	79,171
Natural Gas Liquids**									
Canada	**13,452**	**12,804**	13,588	13,971	14,278	13,348	13,758	14,740	15,291
United States	**12,126**	**14,363**	12,752	9,237	9,291	9,479	9,530	10,194	7,943
Total North America ***	**168,750**	**169,673**	170,687	165,877	165,895	174,471	172,870	159,668	156,295
Ecuador									
Production ****	**77,086**	**76,567**	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	**946**	**(1,721)**	(73)	4,662	(1,355)	4,621	(9,856)	2,506	(2,679)
Ecuador Sales	**78,032**	**74,846**	78,303	80,982	46,521	77,352	39,807	37,221	31,273
United Kingdom	**17,890**	**14,889**	20,728	18,088	10,128	15,067	5,813	9,019	10,610
Total Oil and Natural Gas Liquids	**264,672**	**259,408**	269,718	264,947	222,544	266,890	218,490	205,908	198,178
Total *(BOE/d)*	**758,005**	**780,741**	775,885	716,947	650,211	713,890	639,323	617,408	629,678

* Year-to-date 2004 net dispositions total approximately 41 MMcf/day.

** Natural gas liquids include condensate volumes.

*** Year-to-date 2004 net dispositions total approximately 16,000 bbls/day.

**** Year-to-date 2004 includes approximately 31,000 bbls/day related to Block 15.

***** 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 Q3	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Produced Gas – Canada *(US$/Mcf)*									
Price	**5.17**	**5.10**	5.20	5.21	4.87	4.41	4.61	4.92	5.53
Production and mineral taxes	**0.08**	**0.09**	0.07	0.08	0.07	0.10	0.08	0.08	0.02
Transportation and selling	**0.38**	**0.37**	0.35	0.44	0.38	0.44	0.40	0.35	0.33
Operating	**0.52**	**0.50**	0.49	0.56	0.48	0.45	0.50	0.47	0.48
Netback	**4.19**	**4.14**	4.29	4.13	3.94	3.42	3.63	4.02	4.70
Produced Gas – United States *(US$/Mcf)*									
Price	**5.49**	**5.36**	5.72	5.39	4.88	4.71	4.82	4.74	5.32
Production and mineral taxes	**0.63**	**0.57**	0.80	0.51	0.47	0.42	0.46	0.46	0.57
Transportation and selling	**0.32**	**0.26**	0.34	0.39	0.40	0.51	0.39	0.36	0.32
Operating	**0.36**	**0.36**	0.37	0.33	0.28	0.29	0.33	0.31	0.20
Netback	**4.18**	**4.17**	4.21	4.16	3.73	3.49	3.64	3.61	4.23
Produced Gas – Total North America *(US$/Mcf)*									
Price	**5.26**	**5.18**	5.34	5.26	4.87	4.49	4.66	4.88	5.49
Production and mineral taxes	**0.23**	**0.24**	0.27	0.19	0.16	0.18	0.17	0.17	0.14
Transportation and selling	**0.37**	**0.33**	0.35	0.43	0.39	0.46	0.40	0.35	0.33
Operating	**0.47**	**0.46**	0.46	0.50	0.43	0.41	0.46	0.43	0.42
Netback	**4.19**	**4.15**	4.26	4.14	3.89	3.44	3.63	3.93	4.60
Produced Gas – Total Upstream *(US$/Mcf)*									
Price	**5.25**	**5.16**	5.33	5.25	4.86	4.48	4.65	4.86	5.48
Production and mineral taxes	**0.23**	**0.24**	0.26	0.19	0.16	0.18	0.17	0.16	0.14
Transportation and selling	**0.39**	**0.36**	0.37	0.44	0.40	0.47	0.41	0.36	0.34
Operating	**0.47**	**0.45**	0.46	0.49	0.43	0.41	0.46	0.43	0.42
Netback	**4.16**	**4.11**	4.24	4.13	3.87	3.42	3.61	3.91	4.58
Crude Oil – Light and Medium Oil – North America *(US$/bbl)*									
Price	**33.16**	**37.40**	32.43	29.92	26.61	25.53	24.31	27.43	29.34
Production and mineral taxes	**0.83**	**0.85**	0.79	0.86	0.29	0.73	(1.35)	0.71	1.08
Transportation and selling	**1.00**	**1.08**	0.76	1.19	1.42	1.33	0.71	1.73	1.95
Operating	**5.68**	**6.49**	4.84	5.87	6.00	6.28	5.93	6.07	5.68
Netback	**25.65**	**28.98**	26.04	22.00	18.90	17.19	19.02	18.92	20.63
Crude Oil – Heavy Oil – North America *(US$/bbl)*									
Price	**24.04**	**28.01**	22.35	21.48	19.61	18.43	17.93	20.07	22.62
Production and mineral taxes	**0.03**	**0.05**	(0.01)	0.06	(0.03)	0.09	(0.49)	0.34	(0.02)
Transportation and selling	**1.61**	**1.63**	1.50	1.69	1.24	1.54	0.58	1.37	1.56
Operating	**5.02**	**4.79**	4.82	5.44	5.67	4.95	5.93	6.18	5.70
Netback	**17.38**	**21.54**	16.04	14.29	12.73	11.85	11.91	12.18	15.38
Crude Oil – Total North America *(US$/bbl)*									
Price	**27.70**	**31.49**	26.85	24.73	22.29	21.08	20.26	22.95	25.34
Production and mineral taxes	**0.35**	**0.34**	0.35	0.37	0.09	0.33	(0.80)	0.49	0.43
Transportation and selling	**1.36**	**1.42**	1.17	1.50	1.31	1.46	0.63	1.51	1.72
Operating	**5.29**	**5.42**	4.83	5.61	5.80	5.45	5.93	6.13	5.70
Netback	**20.70**	**24.31**	20.50	17.25	15.09	13.84	14.50	14.82	17.49

Operating Statistics – After Royalties (continued)

Per-unit Results *(continued)* *(excluding impact of financial hedging)*	2004 Year-to-date	2004 Q3	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Natural Gas Liquids – Canada *(US$/bbl)*									
Price	**29.65**	**33.46**	28.48	27.27	24.26	25.13	23.52	21.02	27.31
Production and mineral taxes	**–**	**–**	–	–	–	–	–	–	–
Transportation and selling	**0.39**	**0.45**	0.35	0.35	0.17	0.13	0.58	–	–
Netback	**29.26**	**33.01**	28.13	26.92	24.09	25.00	22.94	21.02	27.31
Natural Gas Liquids – United States *(US$/bbl)*									
Price	**34.15**	**36.09**	32.93	32.77	26.97	26.68	25.50	24.64	32.18
Production and mineral taxes	**3.77**	**4.05**	3.93	3.09	2.03	2.69	2.64	1.21	1.55
Transportation and selling	**–**	**–**	–	–	–	–	–	–	–
Netback	**30.38**	**32.04**	29.00	29.68	24.94	23.99	22.86	23.43	30.63
Natural Gas Liquids – Total North America *(US$/bbl)*									
Price	**31.78**	**34.85**	30.63	29.46	25.33	25.77	24.33	22.50	28.98
Production and mineral taxes	**1.79**	**2.14**	1.90	1.23	0.80	1.12	1.08	0.50	0.53
Transportation and selling	**0.20**	**0.21**	0.18	0.21	0.10	0.08	0.35	–	–
Netback	**29.79**	**32.50**	28.55	28.02	24.43	24.57	22.90	22.00	28.45
Total Liquids – Canada *(US$/bbl)*									
Price	**27.85**	**31.63**	26.99	24.95	22.47	21.41	20.54	22.76	25.55
Production and mineral taxes	**0.32**	**0.31**	0.32	0.34	0.08	0.30	(0.73)	0.44	0.38
Transportation and selling	**1.28**	**1.35**	1.10	1.40	1.21	1.36	0.62	1.36	1.54
Operating	**4.83**	**4.98**	4.42	5.11	5.27	5.01	5.43	5.53	5.11
Netback	**21.42**	**24.99**	21.15	18.10	15.91	14.74	15.22	15.43	18.52
Crude Oil – Ecuador *(US$/bbl)*									
Price	**28.25**	**33.47**	27.78	23.82	24.21	23.57	22.13	22.31	30.86
Production and mineral taxes	**1.93**	**2.62**	1.84	1.37	1.47	1.06	0.45	1.11	4.27
Transportation and selling	**2.30**	**2.36**	1.92	2.63	2.56	2.81	2.36	2.41	2.35
Operating	**4.17**	**4.35**	4.14	4.04	4.84	4.62	4.33	5.63	5.09
Netback	**19.85**	**24.14**	19.88	15.78	15.34	15.08	14.99	13.16	19.15
Crude Oil – United Kingdom *(US$/bbl)*									
Price	**35.16**	**40.88**	34.68	31.11	28.11	27.05	27.92	27.17	30.61
Transportation and selling	**2.04**	**2.44**	1.85	1.94	1.97	1.70	1.98	1.86	2.45
Operating	**7.08**	**9.98**	7.84	3.86	5.09	6.23	6.55	4.69	2.92
Netback	**26.04**	**28.46**	24.99	25.31	21.05	19.12	19.39	20.62	25.24
Total Liquids – Total Upstream *(US$/bbl)*									
Price	**28.67**	**32.83**	28.00	25.23	23.25	22.51	21.22	22.93	26.89
Production and mineral taxes	**0.93**	**1.17**	0.91	0.73	0.45	0.59	(0.35)	0.58	1.02
Transportation and selling	**1.57**	**1.61**	1.34	1.76	1.47	1.74	0.95	1.51	1.64
Operating	**4.51**	**4.73**	4.33	4.49	4.93	4.75	5.01	5.22	4.77
Netback	**21.66**	**25.32**	21.42	18.25	16.40	15.43	15.61	15.62	19.46
Total BOE – Total Upstream *(US$/bbl)*									
Price	**30.49**	**31.60**	30.58	29.18	27.15	25.26	25.62	27.10	30.98
Production and mineral taxes	**1.23**	**1.34**	1.35	0.97	0.79	0.89	0.56	0.85	0.88
Transportation and selling	**2.06**	**1.96**	1.93	2.32	2.07	2.42	1.93	1.96	1.90
Operating	**3.39**	**3.38**	3.29	3.53	3.38	3.31	3.53	3.46	3.24
Netback	**23.81**	**24.92**	24.01	22.36	20.91	18.64	19.60	20.83	24.96

Operating Statistics – After Royalties (continued)

Impact of Realized Financial Hedging	2004 Year-to-date	2004 Q3	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Natural gas *($/Mcf)*	**(0.16)**	**(0.15)**	(0.25)	(0.08)	(0.10)	0.16	(0.06)	(0.25)	(0.25)
Liquids *($/bbl)*	**(7.11)**	**(9.28)**	(6.69)	(5.39)	(2.54)	(2.15)	(2.18)	(1.61)	(4.45)
Total *($/BOE)*	**(3.12)**	**(3.69)**	(3.31)	(2.29)	(1.25)	(0.22)	(0.99)	(1.55)	(2.43)

Average Royalty Rates *(excluding impact of realized financial hedging)*	2004 Year-to-date	2004 Q3	2004 Q2	2004 Q1	2003 Year	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Produced Gas									
Canada	**12.7%**	**12.2%**	12.7%	13.3%	12.9%	12.2%	12.9%	14.2%	12.4%
United States	**19.5%**	**18.3%**	21.1%	19.3%	20.0%	19.5%	20.2%	20.1%	20.5%
Crude Oil									
Canada and United States	**9.2%**	**8.8%**	11.6%	9.4%	10.3%	9.7%	9.0%	10.7%	11.8%
Ecuador	**26.8%**	**26.5%**	26.5%	27.4%	25.6%	25.4%	25.7%	24.9%	26.9%
Natural Gas Liquids									
Canada	**15.4%**	**18.5%**	13.1%	14.8%	17.5%	14.7%	16.6%	18.0%	20.2%
United States	**17.6%**	**13.6%**	20.7%	19.2%	17.6%	17.5%	17.0%	17.3%	18.5%
Total Upstream	**14.9%**	**14.4%**	14.3%	15.2%	14.5%	14.4%	14.2%	15.1%	14.4%

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