ENCANA'S SECOND QUARTER CASH FLOW INCREASES 53% TO $1.4 BILLION, EARNINGS APPROACH $1.1 BILLION, INCLUDING TAX AND CURRENCY GAINS

Second quarter 2003 gas sales up 13 percent

CALGARY, ALBERTA – With strong year-over-year production growth and robust oil and natural gas prices, EnCana Corporation's (TSX & NYSE: ECA) second quarter 2003 cash flow reached $1.44 billion, or $2.95 per common share diluted, up 53 percent from $938 million in the second quarter of 2002. Net earnings were $1.07 billion, or $2.21 per common share diluted, including the impact of tax rate changes and foreign exchange gains.

Second quarter earnings included an unrealized after-tax gain of $199 million, or 41 cents per common share diluted, relating to translation of US$ debt and a gain of $486 million, or $1.00 per common share diluted, relating to changes in Canadian and Alberta corporate income tax rates for the oil and gas industry. Canadian federal tax rates were reduced for other industries in 2000. These gains had no impact on cash flow. Excluding these gains, EnCana earned $381 million, or 80 cents per common share diluted.

In the second quarter of 2002, EnCana earned $458 million, or $0.97 per common share diluted, which included an unrealized after-tax gain of $163 million related to foreign exchange on translation of US$ debt and $42 million related to tax rate changes. Excluding these gains, EnCana earned $253 million, or $0.53 per share diluted in the second quarter of 2002. Year over year, second quarter 2003 earnings, excluding these gains, increased 51 percent. Revenues, net of royalties and production taxes, in the second quarter of 2003 were $3.2 billion; capital investment was $1.5 billion.

EnCana recently completed the sale of its remaining 3.75 percent interest in Syncrude and its results are reflected as discontinued operations.

"As we move into the second half, we are on target to achieve industry-leading internal sales growth and record financial and operating performance in 2003. Second quarter natural gas sales increased 13 percent from one year earlier. Strong growth in North American oil and natural gas liquids (NGLs) sales was largely offset by decreased sales in Ecuador. However, the completion of the OCP Pipeline is about to mark an exciting new era of oil production in Ecuador. This technically-advanced, privately-owned and operated pipeline is expected to allow us to more reliably control the delivery of our greatly increased production from wellhead to tidewater in the months and years ahead," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

"EnCana continues to deliver strong financial and operating performance. We are focused on building the intrinsic value of every share by growing production, increasing our reserves, and achieving top-quartile cost performance. Prices remain strong at a time when we expect to achieve second half production growth through North America's largest natural gas drilling program and increased oil volumes from Canada, the U.K. and Ecuador," Morgan said.

SECOND QUARTER NATURAL GAS SALES UP 13 PERCENT IN 2003

Second quarter daily oil, NGLs and natural gas sales averaged 727,000 barrels of oil equivalent (BOE), up 9 percent compared to sales of 669,000 barrels of oil equivalent per day during the second quarter of 2002. Daily natural gas sales increased 13 percent to average 2.9 billion cubic feet compared to 2.6 billion cubic feet during the same period in 2002. Oil and NGLs sales averaged 240,000 barrels per day, compared to 239,000 barrels per day in the second quarter of 2002. EnCana drilled 956 net wells in the second quarter of 2003. Operating costs averaged $4.03 per barrel of oil equivalent for the quarter, on track to achieve the company's 2003 target of $3.80 to $4.10 per barrel of oil equivalent.

FOCUSED UPSTREAM INVESTMENT STRATEGY

EnCana continues to focus its investment strategy on high-working interest, upstream assets where the company's staff can apply their core competencies. On July 10, EnCana completed the sale of its remaining 3.75 percent interest in the Syncrude oilsands surface mining operation for approximately $417 million, subject to closing and post-closing adjustments. Future Alberta oilsands development will concentrate on EnCana's huge, 100-percent-owned resources where the company is the leader in new generation thermal enhanced recovery from horizontally-drilled wells. EnCana also recently reached an agreement to increase its interests in the Scott and Telford producing oil fields in the U.K. central North Sea. This agreement involved the exchange of a 22.5 percent non-operated interest in the Llano oil discovery in the Gulf of Mexico.

GROWTH FOUNDED IN RESOURCE PLAYS

"EnCana's growth forecast is built principally upon our large, long-life resource plays. We expect these high-quality oil and gas reservoirs to deliver predictable and reliable production increases for years ahead. Our resource plays include millions of acres of tight gas sands in Alberta, Wyoming and Colorado, our top-quality oilsands lands in northeast Alberta and our extensive Greater Sierra gas play in northeast British Columbia," Morgan said.

"The confidence we have in our growth forecast is founded in both the strength of our reserve base and our large unbooked resource potential. We estimate that the unbooked 'captured resource potential' on EnCana's existing North America lands is approximately 9 trillion cubic feet of gas and 650 million barrels of oil. We define resource potential as those quantities of oil and gas which are estimated to be potentially recoverable on EnCana's existing land base from known accumulations and which are not currently classified as proved or risked probable reserves.

"It's important to note that our 10 percent per-share growth forecast is based upon captured resources on EnCana lands. Our very large North American and international exploration program provides potential upside," Morgan said.

All references to production, sales and financial information for the first six months of 2002 in this news release text and tables for EnCana are presented on a pro forma basis as if the merger of PanCanadian Energy Corporation ("PanCanadian" or "PCE") and Alberta Energy Company Ltd. ("AEC") had occurred at the beginning of 2002. All dollar figures are Canadian unless otherwise stated.

SIX MONTHS CASH FLOW HITS $3.3 BILLION, EARNINGS MORE THAN $2.3 BILLION

During the first six months of 2003, EnCana's earnings increased 272 percent from the first half of 2002 to $2.3 billion, or $4.79 per common share diluted. Earnings include gains totalling $878 million, or $1.81 per common share diluted, as a result of foreign exchange translation on US$ debt and changes to corporate tax rates. While the stronger Canadian dollar results in gains on the US$ denominated debt, it adversely impacts the average net Canadian dollar price realized by the company on its sales of oil and natural gas, which are either directly denominated in U.S. dollars or denominated in Canadian dollars but closely tied to U.S. currency. Six months 2003 cash flow was up 92 percent over the first half of 2002 to $3.3 billion, or $6.77 per common share diluted. Revenues, net of royalties and production taxes, in the first six months were $7.3 billion. Capital investment was $3.0 billion, while divestiture proceeds were $2.6 billion.

NATURAL GAS PRICES REMAIN STRONG

North American natural gas prices continued to be strong in the wake of weakening supply in Canada and the U.S. In the second quarter, the average AECO index price was $6.99 per thousand cubic feet, up 58 percent from the second quarter of 2002. Storage injections have increased in recent months, but storage volumes remain below long-term averages. Storage demands prior to winter are expected to keep prices strong throughout 2003.

WORLD OIL PRICES REMAIN STRONG IN THE WAKE OF CONTINUED SUPPLY UNCERTAINTY

During the second quarter, the average benchmark West Texas Intermediate crude oil price was US$28.91 per barrel, up 10 percent over the same period last year. Continued unrest in key oil producing regions has kept global oil prices higher than expected. Price volatility is expected to continue.

RISK MANAGEMENT PROGRAMS HELP MITIGATE VOLATILITY

EnCana's risk management program is designed to partially mitigate the volatility associated with commodity prices, exchange rates and interest rates. EnCana has entered into various fixed-price transactions for a portion of its forecast 2003 sales as a means of managing the cash flow at risk, thereby stabilizing financial strength and funding for capital programs. With the high oil and gas prices and changes to exchange rates in the second quarter, EnCana's commodity price and currency risk management measures resulted in pre-tax revenue being lower by approximately $120 million, comprised of $42 million on oil sales and $78 million on gas sales. The detailed risk management positions are given in Note 10 to the second quarter Consolidated Financial Statements.

Consolidated EnCana Highlights

FINANCIAL HIGHLIGHTS

(unaudited) *(as at and for the periods ended June 30)* *($ millions, except per share amounts)*	**Q2 2003 Actuals**	Q2 2002 Actuals	**6 Months 2003 Actuals**	6 Months 2002 Pro forma[2]
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	**3,194**	2,586	**7,262**	4,748
Cash Flow	**1,438**	938	**3,290**	1,717
Per common share – diluted	**2.95**	2.00	**6.77**	3.55
Net earnings	**1,066**	458	**2,312**	621
Per common share – basic [1]	**2.24**	0.99	**4.84**	1.31
Per common share – diluted	**2.21**	0.97	**4.79**	1.28
Less				
Foreign exchange gain on translation of US$ debt (after-tax)	**199**	163	**392**	162
Per common share – basic	**0.41**	0.35	**0.82**	0.34
Per common share – diluted	**0.41**	0.35	**0.81**	0.33
Less				
Tax rate change gain	**486**	42	**486**	42
Per common share – basic	**1.01**	0.09	**1.01**	0.09
Per common share – diluted	**1.00**	0.09	**1.00**	0.09
Net earnings, excluding gains	**381**	253	**1,434**	417
Per common share – basic	**0.82**	0.55	**3.01**	0.88
Per common share – diluted	**0.80**	0.53	**2.98**	0.86
Capital investment	**1,505**	1,390	**3,031**	2,644
				at Dec. 31/02
Total assets			**29,603**	31,322
Long-term debt			**6,122**	7,395
Preferred securities			**549**	583
Shareholders' equity			**15,356**	13,794
Debt-to-capitalization ratio (adjusted for working capital & including preferred securities as debt)			**28%**	31%
Common shares				
Outstanding at June 30 (millions)	**479.9**	476.3	**479.9**	476.3
Weighted average diluted (millions)	**486.9**	470.0	**486.3**	483.6

[1] **Impact of including share options in earnings calculations**
If EnCana were to record compensation expense for outstanding share options, net earnings per common share – basic would have been $4.78 per common share, 6 cents per common share less, for the first six months of 2003.

[2] **Important Notice: Readers are cautioned that comparisons to 2002 six months results are based on pro forma calculations and these pro forma results may not reflect all adjustments and reconciliations that may be required under Canadian generally accepted accounting principles. These pro forma results may not be indicative of the results that actually would have occurred or of the results that may be obtained in the future. Also, certain information provided for prior years has been reclassified to conform to the presentation adopted in 2003.**

Consolidated EnCana Highlights

OPERATING HIGHLIGHTS

(for the period ended June 30)	**Q2 2003 Actuals**	Q2 2002 Actuals	% Change	**6 Months 2003 Actuals**	6 Months 2002 Pro forma[2]	% Change
SALES						
Natural gas *(MMcf/d)*						
North America	**2,911**	2,572	+13	**2,956**	2,641	+12
U.K.	**12**	8	+50	**12**	10	+20
Total natural gas *(MMcf/d)*	**2,923**	2,580	+13	**2,968**	2,651	+12
Oil and NGLs *(bbls/d)*						
North America	**181,250**	166,951	+9	**180,527**	165,304	+9
Ecuador	**49,575**	59,864	–17	**46,189**	49,377	–6
U.K.	**9,019**	11,966	–25	**9,810**	12,425	–21
Total oil and NGLs* *(bbls/d)*	**239,844**	238,781	–	**236,526**	227,106	+4
Total sales *(BOE/d)**	**727,011**	668,781	+9	**731,193**	668,939	+9
Prices, including hedging						
Natural Gas *($/Mcf)*						
Canada	**6.12**	4.11	+49	**6.67**	3.75	+78
U.S.	**5.89**	3.62	+63	**7.09**	3.53	+101
North American gas *($/Mcf)*	**6.06**	4.02	+51	**6.77**	3.72	+82
North American oil *($/bbl)*						
Light/medium	**32.22**	33.76	–5	**32.39**	29.84	+9
Heavy	**23.20**	26.09	–11	**23.08**	23.95	–4
International crude oil *($/bbl)*						
Ecuador	**29.50**	31.63	–7	**36.13**	27.90	+29
U.K.	**35.58**	37.78	–6	**39.25**	34.15	+15
Natural gas liquids *($/bbl)*	**31.45**	29.92	+5	**37.41**	26.34	+42
Total liquids *($/bbl)*	**28.23**	30.59	–8	**30.44**	27.41	+11

* Excludes Syncrude which averaged 7,383 barrels per day in the second quarter of 2003, compared to 24,295 barrels per day in the second quarter of 2002. For the first six months of 2003, Syncrude averaged 13,792 barrels per day.

[2] See footnote on previous page

Forecast of 10 percent internal sales growth in 2003 and 2004 confirmed

Total 2003 daily oil, NGLs and natural gas sales volumes from continuing operations are forecast to increase approximately 10 percent from pro forma 2002 levels, averaging between 740,000 and 797,000 barrels of oil equivalent, which is comprised of between 3 billion and 3.1 billion cubic feet of gas per day and 240,000 and 280,000 barrels of oil and NGLs per day. In 2004, daily oil, NGLs and natural gas sales are expected to average between 805,000 and 885,000 barrels of oil equivalent, comprised of natural gas sales between 3.25 billion and 3.45 billion cubic feet per day and 265,000 and 310,000 barrels of oil and NGLs per day, representing a 10 percent increase from forecast 2003 sales levels.

CORPORATE DEVELOPMENTS

Normal Course Issuer Bid purchases

As of July 28, 2003, EnCana has invested approximately $358 million purchasing 7,112,800 of its common shares for cancellation at an average price of $50.38 per common share under the company's Normal Course Issuer Bid, which allows for purchases of up to 23,843,565 common shares, representing 5 percent of the outstanding shares on October 4, 2002. The company expects to continue to purchase shares under the terms of its current bid and it intends to apply to renew the bid, which expires October 21, 2003.

Dividend

The board of directors of EnCana declared a quarterly dividend of 10 cents per share payable on September 30, 2003 to common shareholders of record as of September 12, 2003.

FINANCIAL STRENGTH

EnCana has one of the strongest balance sheets among North American independents. At June 30, 2003, the company's debt-to-capitalization ratio was 28:72 (preferred securities included as debt). EnCana's debt-to-EBITDA multiple, on a trailing 12-month basis, was 0.9 times. Second quarter capital investment was $1,505 million. Net proceeds from asset dispositions were $17 million, resulting in net capital investment of $1,488 million.

EnCana's 2003 net capital investment is forecast to be between $2.5 billion and $2.9 billion as outlined below.

EnCana 2003 forecast capital program *(millions)*

Core capital program (forecast)	$	**5,000 - 5,400**
Additional capital		
Ecuador reserves and land acquisition	$	180
Leased equipment purchases	$	290
OCP Pipeline completion requirements	$	100
Sub total	$	570
Divestitures		
Express and Cold Lake pipelines[3]	$	(1,600)
Syncrude	$	(1,500)
Sub total	$	(3,100)
Net capital investment (forecast)	$	**2,470 - 2,870**

[3] $1.6 billion less $600 million of net assumption of debt resulted in net cash proceeds of $1.0 billion.

EnCana maintains strong investment grade ratings from the major bond rating services: Dominion Bond Rating Service Limited, A(low), Moody's Investors Service, Baa1, and Standard and Poor's Ratings Services, A-. The company also has a $4 billion credit facility with a syndicate of major banks and lending institutions, of which more than $2.6 billion remains unutilized.

OPERATIONAL HIGHLIGHTS

North America

Second quarter natural gas and liquids sales up 12 percent year over year

North American gas, oil and NGLs sales continued to grow at double digit rates in the second quarter, averaging 666,417 barrels of oil equivalent per day – a 12 percent increase over the average of 595,618 barrels of oil equivalent per day in the second quarter of 2002. Natural gas sales were up 13 percent, averaging 2.9 billion cubic feet per day. EnCana currently has no produced gas in storage. Liquids production was up 9 percent year over year, averaging 181,250 barrels per day.

Growth in gas production was led by increased production from the U.S. Rockies and the Greater Sierra area in northeast B.C. Oil production continues to increase from EnCana's two steam-assisted gravity drainage (SAGD) projects in northeast Alberta, as well as from continued development at Pelican Lake and Suffield. In North America, EnCana drilled 944 net wells during the second quarter and has about 100 rigs running this summer from northeast B.C. to Colorado.

USA region growth strong, led by Rockies production

Second quarter gas sales from the USA region were up 63 percent to average 698 million cubic feet per day, compared to an average of 428 million cubic feet per day for the same period in 2002. Production growth is primarily from the Jonah field in Wyoming and the Mamm Creek field in Colorado. In order to help mitigate pricing risk due to gas transmission constraints out of the U.S. Rockies, EnCana has fixed the NYMEX price differential on 576 million cubic feet per day of forecast 2003 gas sales at an average basis of US$0.50 per thousand cubic feet, and 392 million cubic feet per day of forecast gas sales for 2004 through 2007 at an average basis of US$0.44 per thousand cubic feet.

"Our U.S. Rockies business continues to deliver very strong growth. We are currently producing more than 700 million cubic feet per day and expect to continue double-digit production growth for years to come," said Roger Biemans, President of EnCana's USA Region.

In the Gulf of Mexico, appraisal drilling on the Tahiti discovery has confirmed one of the most significant net pay accumulations in the history of deep water drilling in the Gulf. EnCana continues to work with the operator in development planning for this promising oil find.

Summer drilling ramps up in northeast British Columbia

Production from the Greater Sierra area of northeast B.C. averaged about 200 million cubic feet per day in the second quarter, an increase of more than 25 percent from one year earlier. EnCana has pioneered new ways to add value in this high growth region through the use of interlocking wooden mats – a simple technology that forms drilling islands in the soft Canadian muskeg. Traditionally, northern exploration and drilling have been restricted to winter only – the 100 days when the ground is frozen hard enough to permit the movement of large equipment. But with the availability of more than 30,000 wooden mats, EnCana recently doubled its summer drilling plans from 35 to 70 wells, taking this year's target for Greater Sierra to about 170 wells.

"The use of these wooden mats can truly change the way oil and gas companies do business during summer in the remote northern regions. Until now, these wet muskeg lands have only seen modest drilling activity during the warmest part of the year. We expect to reduce costs in both summer and winter as we achieve a more balanced drilling program through the entire year," said Randy Eresman, EnCana's Chief Operating Officer.

With a total land base of more than 2.4 million net acres along this prolific gas trend, EnCana has a multi-year inventory of development drilling locations. In anticipation of the region's growth potential, EnCana has applied to the National Energy Board to construct a new, 80-kilometre pipeline to deliver, by mid 2004, in excess of 100 million cubic feet of natural gas from the company's Sierra gas plant to a connection on the Nova Gas Transmission mainline in northwest Alberta. In addition, recent initiatives by the B.C. government have improved the region's growth opportunities for several years ahead.

"EnCana welcomes the province's recent plans to improve road infrastructure, streamline the regulatory process, upgrade the Sierra Yoyo Desan road and adopt a royalty structure that increases the region's competitiveness. These progressive changes have added new confidence to our strong expected growth and investment plans for B.C. We have expanded investment and drilling in our world-class Greater Sierra resource play, where the company now expects to grow production to more than 400 million cubic feet per day over the next few years," Eresman said.

Next phase of SAGD growth well underway

With design capacity of 20,000 barrels per day of production successfully achieved at Foster Creek, EnCana plans to increase oil production from its largest SAGD project by about 10,000 barrels per day in 2004. An additional six well pairs, taking the project's total to 30 well pairs, are being drilled to tap additional reserves. Since May, the new Foster Creek co-generation plant has been delivering about 40 megawatts of electricity to the Alberta power grid, and output is expected to increase to its full capacity of 80 megawatts in the fourth quarter of 2003.

International

Second quarter oil and NGLs sales from international operations averaged 58,594 barrels per day, down about 18 percent from the second quarter last year.

Ecuador oil production about to ramp up, first OCP Pipeline oil deliveries expected this summer.

Second quarter sales in Ecuador averaged 49,575 barrels of oil per day, down about 17 percent from an average of 59,864 barrels per day one year earlier. The decrease is due to about 2,800 barrels per day having been delivered to the new OCP Pipeline for commissioning, timing of shipments from port and operational problems on the SOTE pipeline, currently Ecuador's main oil export pipeline. EnCana's production capability is approximately 80,000 barrels per day, with additional capacity available to be added through the last half of the year. Mainline and facilities construction of the OCP Pipeline is nearing completion and it is expected that oil deliveries for export will begin in mid to late August. EnCana production will be ramped up once the OCP is fully operational, with a doubling of its production levels to about 100,000 barrels per day targeted for 2004.

"EnCana is pleased to see the completion of this monumental economic development for the people of Ecuador. This is the culmination of more than four years of challenging work by EnCana and its partners that will see critically-needed investment and revenue growth for this proud South American nation," said Don Swystun, President of EnCana's Ecuador region.

EnCana expands interests in U.K. central North Sea, Buzzard development progresses

EnCana has reached an agreement with Amerada Hess to acquire an additional 14 percent interest in each of the Scott and Telford oil fields. This transaction will increase EnCana's working interest in the Scott field from 13.5 to 27.5 percent and in the Telford field from 20.2 to 34.2 percent in exchange for EnCana's 22.5 percent non-producing working interest in the Llano oil discovery in the Gulf of Mexico. On closing, expected this fall, EnCana will become the largest working interest owner of both the Scott and Telford fields, where EnCana is also seeking approval to become the operator. Net production is anticipated to increase from a year-to-date production of about 11,500 barrels of oil equivalent per day to approximately 20,000 barrels of oil equivalent per day. In addition, EnCana has agreed to acquire Amerada Hess' 42.1 percent working interest in Block 15/21 outside of the Scott and Telford and Ivanhoe and Rob Roy field units.

In June, EnCana filed the environmental statement with the Department of Trade and Industry for the development of the Buzzard field, which is expected to start production in late 2006.

Midstream & Marketing

EnCana's Midstream & Marketing division experienced a $40 million operating cash flow loss in the second quarter of 2003, including the impact of the regulatory settlement referred to in EnCana's July 28, 2003 news release. The results reflect a challenging first half for gas storage, as low summer/winter gas price spreads reduced demand for storage services and limited margin opportunities. In addition, NGLs extraction was adversely impacted by low processing margins as a result of the strong natural gas prices. For the full year, operating cash flow is now expected to be in the range of $100 million to $130 million.

New gas storage at Countess starts operations, Wild Goose expansion in California ahead of schedule

EnCana has started injecting customers' natural gas into the first 10 billion cubic feet of new storage capacity at Countess, Alberta, located about 85 kilometres east of Calgary. The second phase of Countess is expected to take total capacity from 10 billion to about 40 billion cubic feet by April 2005. In northern California, Wild Goose Storage Inc. is expected to expand the gas deliverability from the storage facility by November, four months ahead of schedule and in time for the winter season. November withdrawal capacity is expected to rise from 200 million to 320 million cubic feet per day. This first phase of the Wild Goose expansion is expected to be fully operational by April 2004, when withdrawal capacity is expected to more than double from the current 200 million to 480 million cubic feet per day. Gas storage capacity is planned to increase from 14 billion to approximately 24 billion cubic feet, while injection capacity is expected to rise from 80 million to 450 million cubic feet per day. A second phase of expansion anticipates increasing capacity to about 29 billion cubic feet and withdrawal rates to 700 million cubic feet per day by spring 2005, depending upon market demand.

FINANCIAL INFORMATION

NOTE: All financial information in this news release is actual results, except for the company's 2002 pro forma six-month financial results, which reflect the results of PanCanadian and AEC as if they had merged at the beginning of 2002. The actual statements for the first six months of 2002 represent PanCanadian results alone during the first quarter of 2002 as the merger did not occur until the beginning of April 2002.

This press release and EnCana's supplemental information, including convenience financial statements prepared in $US, are posted on the company's Web site: www.encana.com.

ENCANA CORPORATION

EnCana is one of the world's leading independent oil and gas companies with an enterprise value of approximately C$30 billion. EnCana is North America's largest independent natural gas producer and gas storage operator. Ninety percent of the company's assets are in four key North American growth platforms. 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 deepwater Gulf of Mexico. The company has two key high potential international growth platforms: through its international subsidiaries, EnCana is the largest private sector oil producer in Ecuador and is the operator of a large oil discovery in the U.K. central North Sea. The company also conducts 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 – 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: future economic performance, including production and sales growth targets for 2003, 2004 and beyond (including per share sales growth); anticipated increases in production, including increases achieved through successful drilling programs, from Ecuador upon completion of the OCP pipeline, from the USA region and from the U.K.; the company's ability to achieve per share sales and production growth targets over the next several years and the predictability thereof; projected drilling activity in North America in 2003 and beyond; resource potential, reserves and production increases potentially available from the Company's resource plays, including resource plays located in Alberta, British Columbia, Wyoming and Colorado; the demand for gas storage and its effect on gas prices through the remainder of 2003; anticipated oil and natural gas prices for the remainder of 2003 and continued volatility of world oil prices; forecast oil, gas and natural gas liquids sales volumes for 2003; increased electrical generation capacity from the Foster Creek co-generation plant expected in the fourth quarter of 2003; the timing for completion and capacity of the company's proposed new pipeline; the impact of EnCana's risk management program on commodity price, interest rate and exchange rate volatility; increased oil production from SAGD projects by 2004; the timing for commencement of oil shipments through the OCP pipeline and projected capacity utilization in 2003 and 2004; the timing for completion of the various phases of the Countess gas storage project and the Wild Goose gas storage project in 2003, 2004, 2005 and beyond, and storage capacities, injection and withdrawal rates upon completion; the timing for completion and commencement of production from the Buzzard field; anticipated purchases under the Company's Normal Course Issuer Bid program and the potential renewal of the Normal Course Issuer Bid; increased capital expenditures for 2003; the impact of the use of wooden mats on summer drilling and drilling costs; EnCana's internal projections, expectations or beliefs concerning future operating results, and various components thereof; EnCana's ability to invest selectively and returns on such investments; and the production and growth potential of EnCana's various assets, including assets in the U.S. Rockies, Greater Sierra, offshore Canada's East Coast, the U.K. central North Sea, the Gulf of Mexico and Ecuador.

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 reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved or probable 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 international war, hostilities, civil insurrection and instability affecting countries in which the company operates and international terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; the risk that the anticipated synergies to be realized by the merger of AEC and PCE will not be realized; costs relating to the merger of AEC and PCE being higher than anticipated 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 interim report 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.

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

ADVISORY – In the interest of providing EnCana Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company and its subsidiaries, certain statements throughout this Management's Discussion and Analysis ("MD&A") constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: the expected closing date for the transactions relating to the Scott, Telford and Llano properties; the Company's oilsands strategy; royalty rates, production, federal and provincial taxes and tax rates for various periods, including 2003 to 2007 and the Company's expectations regarding future income taxes; the timing for completion and commencement of oil shipments through the OCP pipeline; the timing for completion of the various phases of the Countess and Wild Goose gas storage projects, and storage capacities, injection and withdrawal rates expected upon completion; the effect of certain forward contracts on future capital funding requirements; the impact of pipeline capacity on AECO production area prices; the production and growth potential of EnCana's and its subsidiaries' various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea, the Gulf of Mexico and potential new ventures exploration growth platforms; production and sales targets for oil, natural gas and natural gas liquids for 2003 and 2004; and projected capital investment levels for 2003 and the source of funding therefor.

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 the Company's 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 or probable reserves; the Company's and the Company's 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; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and the Company's 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 international terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions brought against the Company and its subsidiaries; the risk that the anticipated synergies to be realized by the merger of AEC and PCE will not be realized; costs relating to the merger of AEC and PCE being higher than anticipated 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 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.

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 for the period ended June 30, 2003 and June 30, 2002 and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2002

The 2002 comparative figures included in the unaudited interim Consolidated Financial Statements ("Consolidated Financial Statements") for the six months ended June 30, 2003 include the results of the Company prior to the April 5, 2002 merger with Alberta Energy Company Ltd ("AEC"). As such, the amounts reported for the six months ended June 30, 2002 do not include any results related to AEC's operations prior to April 5, 2002.

EnCana reports the results of its continuing operations under two main business segments: Upstream and Midstream & Marketing as further described in Note 3 to the Consolidated Financial Statements.

CONSOLIDATED FINANCIAL RESULTS

EnCana's 2003 second quarter cash flow from continuing operations was $1,483 million, or $3.05 per Common Share-Diluted ("per share"), an increase of 64 percent over $904 million, or $1.92 per share, in the corresponding quarter of 2002. Net earnings from continuing operations were $1,063 million, or $2.20 per share, compared with $482 million, or $1.02 per share, in the second quarter of last year. Significantly higher commodity prices and growth in the Company's sales volumes were the primary factors contributing to the increase in cash flow. In addition to these factors, net earnings in the quarter included a one-time reduction by future income tax liabilities of $486 million resulting from the reductions in the Canadian and Alberta corporate income tax rates and an unrealized after-tax gain on the translation of U.S. dollar debt of $199 million. The Canadian tax rate reduction for the oil and gas industry reflects the rate reduction enacted for other Canadian industries in 2000.

For the six months ended June 30, 2003, cash flow from continuing operations of $3,290 million, or $6.77 per share increased 155 percent from $1,291 million, or $3.54 per share, in the same period last year. The Company's net earnings from continuing operations were $2,019 million, or $4.19 per share, up from $613 million or $1.68 per share in the first six months of 2002. The improvement in the year-to-date cash flow results reflected the inclusion of post-merger operations for the full six-month period in 2003, as well as higher commodity prices and growth in sales volumes. Net earnings for the first half of the year included the previously mentioned $486 million recovery of future income tax liabilities and an unrealized after-tax gain on the translation of U.S. dollar debt of $392 million.

Consolidated Financial Summary	Three Months Ended June 30		Six Months Ended June 30	
($ millions, except per share amounts)	**2003**	2002	**2003**	2002
Revenues, Net of Royalties and Production Taxes	**$ 3,194**	$ 2,586	**$ 7,262**	$ 3,647
Net Earnings from Continuing Operations	**1,063**	482	**2,019**	613
- per share	**2.20**	1.02	**4.19**	1.68
Net Earnings	**1,066**	458	**2,312**	591
- per share	**2.21**	0.97	**4.79**	1.62
Cash Flow from Continuing Operations	**1,483**	904	**3,290**	1,291
- per share	**3.05**	1.92	**6.77**	3.54
Cash Flow	**1,438**	938	**3,290**	1,327
- per share	**2.95**	2.00	**6.77**	3.64

In accordance with Canadian generally accepted accounting principles ("GAAP"), the Company is required to translate long-term debt borrowed 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 or, in the case of long-term debt held by self-sustaining foreign operations, in the foreign currency translation adjustment account included in Shareholders' Equity in the Consolidated Balance Sheet. In order to provide shareholders and potential investors with information clearly presenting the effect of the translation of the outstanding U.S. dollar debt on the Company's results, the following table has been prepared. The majority of these unrealized gains/losses relate to debt with maturity dates in excess of 5 years.

($ millions)	2003 Year-to-date	2003 Q2	2003 Q1	2002 Q4	2002 Q3	2002 Q2
Net Earnings from Continuing Operations, as reported	**$2,019**	**$1,063**	$ 956	$ 374	$ 116	$ 482
Deduct: Foreign exchange gain/(loss) on translation of U.S. dollar debt (after-tax)*	**392**	**199**	193	10	(145)	163
Earnings from Continuing Operations, excluding foreign exchange on translation of U.S. dollar debt	**$1,627**	**$ 864**	$ 763	$ 364	$ 261	$ 319
($ per Common Share - Diluted)						
Net Earnings from Continuing Operations, as reported	**$ 4.19**	**$ 2.20**	$ 1.98	$ 0.77	$ 0.24	$ 1.02
Deduct: Foreign exchange gain/(loss) on translation of U.S. dollar debt (after-tax)*	**0.81**	**0.41**	0.40	0.02	(0.30)	0.35
Earnings from Continuing Operations, excluding foreign exchange on translation of U.S. dollar debt	**$ 3.38**	**$ 1.79**	$ 1.58	$ 0.75	$ 0.54	$ 0.67

* As this is an unrealized gain/(loss), there is no impact on cash flow.

Earnings from Continuing Operations, excluding foreign exchange on the translation of U.S. dollar debt, and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this discussion and analysis in order to provide shareholders and potential investors with additional information regarding the Company's finances and results of operations.

ACQUISITIONS AND DIVESTITURES

In June, 2003, the Company's subsidiaries entered into agreements to exchange a 22.5 percent interest in the Llano field in the Gulf of Mexico for a 14 percent interest in both the Scott and Telford oil fields in the U.K. central North Sea. As a result, EnCana's U.K. subsidiary will become the largest working interest owner in both the Scott and Telford fields. Completion of this transaction is contingent upon the U.K. subsidiary becoming operator of Scott and Telford, which requires co-venture and regulatory approval. This transaction is expected to close this fall.

On January 31, 2003, the Company expanded its production and landholdings in Ecuador through the purchase of a corporation for net cash consideration of approximately $179 million. This acquisition included interests in developed and undeveloped reserves in three blocks adjacent to Block 15, where another subsidiary has an existing non-operated working interest.

Discontinued Operations

Syncrude

On July 10, 2003, subsidiaries of the Company completed the sale of their remaining 3.75 percent working interest together with EnCana's gross-overriding royalty in the Syncrude Joint Venture for total proceeds of approximately $417 million, subject to normal post-closing adjustments. The sale completed the Company's and its subsidiaries' disposition of their entire interest in the Syncrude project. An initial sale of a 10 percent interest in the Syncrude project was completed on February 28, 2003 for net cash consideration of $1,026 million, before post-closing adjustments. There was no gain or loss on this sale. Net earnings from Syncrude operations were $3 million in the quarter, $30 million for the six months ended June 30, 2003.

With the sale of the Syncrude interest, the Company intends to focus its oilsands strategy on developing its high quality bitumen resources, recovered through producing wells using steam-assisted gravity drainage ("SAGD") technology, on 100 percent owned and operated lands at Foster Creek and Christina Lake.

Midstream - Pipelines

Subsidiaries of the Company closed the sale of their interests in the Cold Lake Pipeline System and Express Pipeline System on January 2, 2003 and January 9, 2003, respectively, for total consideration of approximately $1.6 billion, including the assumption of related long-term debt. An after-tax gain on sale of $263 million was recorded in relation to these transactions.

These pipeline sales were part of EnCana's strategic realignment to focus on its large portfolio of higher return growth assets. The proceeds were used for general corporate purposes, including debt reduction, prior to being re-deployed.

The Syncrude and Midstream-Pipelines operations described above have been accounted for as discontinued operations as described in Note 4 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

	Three Months Ended June 30		Six Months Ended June 30	
(average for the period)	**2003**	2002	**2003**	2002
AECO Price *($ per thousand cubic feet)*	**$ 6.99**	$4.42	**$ 7.46**	$3.88
NYMEX Price *(US$ per million British thermal unit)*	**5.41**	3.40	**6.00**	2.86
WTI *(US$ per barrel)*	**28.91**	26.27	**31.32**	23.95
WTI/Bow River Differential *(US$ per barrel)*	**6.58**	5.43	**7.10**	5.33
WTI/Oriente Differential (Ecuador) *(US$ per barrel)*	**6.32**	3.78	**5.69**	4.35
U.S./Canadian dollar exchange rate *(US$)*	**0.717**	0.643	**0.688**	0.635

Natural gas prices in the second quarter of 2003 were significantly higher than prices in the same quarter last year. The average AECO index price was $6.99 per thousand cubic feet, up 58 percent from $4.42 per thousand cubic feet in the second quarter of 2002. The NYMEX average price was also higher at US$5.41 per million British thermal unit, an increase of 59 percent over the second quarter of 2002. Higher prices in the second quarter were the result of higher than normal demand for storage injections. Colder weather in the first quarter of 2003 also contributed to the higher average gas prices in the first six months of 2003.

The benchmark West Texas Intermediate ("WTI") crude oil price was higher for both the second quarter of 2003 and the year-to-date. The higher prices reflected the impact of continued low levels of world oil inventories, market uncertainty over Iraqi supply, civil strife in Nigeria and reduced Venezuelan production.

The differential between heavy and light crude oil prices in 2003 widened over 2002 differentials. Both the WTI/Bow River differential and the WTI/Oriente differential were wider in comparison to the second quarter and first six months of last year. This was driven by a higher average WTI price and soft asphalt demand in 2003. Also contributing to the wider differentials were additional Canadian heavy crude coming on stream and increased freight rates on Oriente crude.

The Canadian dollar continued to strengthen relative to the U.S. dollar during the first six months of 2003. The U.S./Canadian dollar exchange rate averaged US$0.717 per $1 Canadian in the second quarter, an improvement over an average rate of US$0.643 per $1 Canadian during the same period last year. The year-to-date U.S/Canadian dollar exchange rate averaged US$0.688 per $1 Canadian compared with an average of US$0.635 per $1 Canadian in the first six months of 2002. The strengthening of the Canadian dollar was primarily the result of a widening spread between Canadian and U.S. interest rates and a weaker economic climate in the U.S. While the stronger Canadian dollar results in gains on the U.S. dollar denominated debt, it adversely impacts the average net Canadian dollar price realized by the Company on its sales of oil and natural gas, which are either directly denominated in U.S. dollars or denominated in Canadian dollars but closely tied to U.S. currency.

RESULTS OF OPERATIONS

*Upstream**

Three Months Ended June 30

($ millions)	2003 Produced Gas & NGLs	2003 Crude Oil	2003 Non-Producing	2003 Total	2002 Produced Gas & NGLs	2002 Crude Oil	2002 Non-Producing	2002 Total
Revenues								
Gross revenue	$ 1,820	$ 569	$ 64	$ 2,453	$1,136	$ 618	$ 19	$1,773
Royalties and production taxes	340	94	–	434	174	107	–	281
Revenues, net of royalties and production taxes	1,480	475	64	2,019	962	511	19	1,492
Expenses								
Transportation and selling	115	39	–	154	85	22	–	107
Operating	143	138	57	338	122	118	30	270
Depreciation, depletion and amortization	472	226	2	700	363	169	3	535
Upstream Income	$ 750	$ 72	$ 5	$ 827	$ 392	$ 202	$ (14)	$ 580

Six Months Ended June 30

($ millions)	2003 Produced Gas & NGLs	2003 Crude Oil	2003 Non-Producing	2003 Total	2002 Produced Gas & NGLs	2002 Crude Oil	2002 Non-Producing	2002 Total
Revenues								
Gross revenue	$ 4,078	$ 1,182	$ 109	$ 5,369	$ 1,534	$ 858	$ 35	$ 2,427
Royalties and production taxes	708	225	–	933	209	140	–	349
Revenues, net of royalties and production taxes	3,370	957	109	4,436	1,325	718	35	2,078
Expenses								
Transportation and selling	233	83	–	316	118	33	–	151
Operating	293	266	110	669	171	173	36	380
Depreciation, depletion and amortization	981	435	4	1,420	499	233	6	738
Upstream Income	$ 1,863	$ 173	$ (5)	$ 2,031	$ 537	$ 279	$ (7)	$ 809

* Upstream results exclude Syncrude operations, which have been accounted for as discontinued operations as described in Note 4 to the Consolidated Financial Statements.

Sales Volumes*	Three Months Ended June 30 2003	Three Months Ended June 30 2002	Six Months Ended June 30 2003	Six Months Ended June 30 2002
Produced Gas *(million cubic feet per day)*	2,923	2,580	2,968	1,837
Crude Oil (*barrels per day)*	208,927	213,457	206,039	157,228
NGLs *(barrels per day)*	30,917	25,324	30,487	20,929
Total Conventional *(barrel of oil equivalent per day)**	727,011	668,781	731,193	484,324

* Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent

Revenue Variances for 2003 Compared to 2002 *($ millions)*	Three Months Ended June 30 Price	Three Months Ended June 30 Volume	Three Months Ended June 30 Total	Six Months Ended June 30 Price	Six Months Ended June 30 Volume	Six Months Ended June 30 Total
Produced Gas and NGLs	$ 532	$ 152	$ 684	$ 1,602	$ 942	$ 2,544
Conventional Crude Oil	(36)	(13)	(49)	58	266	324
Total Gross Revenue*	$ 496	$ 139	$ 635	$1,660	$ 1,208	$ 2,868

* Excludes gross revenue from Non-Producing Operations

Consolidated Upstream Results

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry. In the second quarter of 2003, gross revenue from the Company's upstream operations was $2,453 million, an increase of $680 million, or 38 percent, over gross revenue of $1,773 million in the second quarter of 2002. The increase in the quarter primarily reflects the benefit of higher realized natural gas prices, an increase in natural gas sales stemming primarily from acquisitions by subsidiaries in the U.S. Rockies and continued development at Jonah, Mamm Creek and Greater Sierra.

Upstream gross revenue for the first six months of 2003 was $5,369 million, up $2,942 million, or 121 percent from the first six months of last year. In addition to higher commodity prices, the increase in gross revenue reflected the benefit of the growth in sales volumes resulting from the merger with AEC, acquisitions in the U.S. Rockies, expansion of the Company's SAGD projects and continued development in both Canada and the U.S. Rockies.

The following table provides a summary of royalties as a percentage of the Company's realized commodity prices, net of transportation and selling costs and excluding the impact of financial hedging:

Average Royalty Rates (%)	Three Months Ended June 30		Six Months Ended June 30	
(excluding the impact of financial hedging)	**2003**	2002	**2003**	2002
Produced Gas				
Canada	**16%**	15%	**14%**	14%
U.S.*	**21%**	20%	**20%**	22%
NGLs - North America	**19%**	16%	**20%**	12%
Crude Oil				
North America	**12%**	12%	**13%**	13%
Ecuador	**33%**	34%	**36%**	34%
Total Upstream	**18%**	17%	**17%**	16%

* Excludes U.S. production taxes of approximately 8 percent

As shown in the table above, royalties were 18 percent in the second quarter, up marginally from 17 percent in the same quarter of last year. For the six months ended June 30, 2003, royalties averaged 17 percent compared with 16 percent in the same period of 2002. This year-to-date rate is on track with the Company's guidance, which anticipates a royalty rate of 18 percent for the 2003 year.

Transportation and selling costs totalled $154 million in the quarter and $316 million for the year to date compared with costs of $107 million and $151 million in the respective periods of 2002. The higher costs are primarily the result of higher sales volumes in 2003. For the purpose of the revenue discussions below, these costs have been netted against gross revenue in calculating the per unit realized prices for each commodity.

Crude oil and natural gas operating expenses, excluding costs related to non-producing activities, were $281 million in the second quarter, an increase of $41 million over the second quarter of 2002 primarily due to higher levels of production in 2003. On a per unit basis, operating expenses, including cost recoveries, were $4.03 per barrel of oil equivalent in the quarter up from $3.77 per barrel of oil equivalent in the same quarter of last year. The increase is mainly due to increased maintenance, workovers, power and fuel costs, combined with increased production weighting from SAGD projects.

In the first six months of the year, upstream operating costs, excluding expenses related to non-producing activities, were $559 million compared with costs of $344 million in the same period of 2002. Inclusion of the full six months of post-merger production, acquisitions by subsidiaries in the U.S. Rockies, expansion of the SAGD projects, and continued development in both Canada and the U.S. Rockies, were the primary factors contributing to the increase. For the year to date, these costs, including cost recoveries, were $4.08 per barrel of oil equivalent, which compared with $3.73 per barrel of oil equivalent in the first half of 2002. The higher unit operating expense primarily reflected increased maintenance, workovers, power and fuel costs, combined with an increased production weighting from SAGD projects.

Depreciation, depletion and amortization ("DD&A") charges totalled $700 million, or $10.58 per barrel of oil equivalent, in the second quarter of 2003 compared with $535 million, or $8.79 per barrel of oil equivalent, in the same quarter last year. For the first six months of 2003, DD&A charges amounted to $1,420 million, or $10.73 per barrel of oil equivalent, up from $738 million, or $8.42 per barrel of oil equivalent in the same period of 2002. The 2003 DD&A rates reflect increased future development costs related to the proven reserves added for SAGD projects and the U.S. Rockies. The 2003 future development costs are approximately $2.30 per barrel of oil equivalent of the DD&A calculation compared to future development costs of $0.83 per barrel of oil equivalent in 2002.

Produced Gas and NGLs

Per-Unit Results - Produced Gas and NGLs

Three Months Ended June 30	Produced Gas - Canada		Produced Gas - U.S.		NGLs - North America	
	2003	2002	**2003**	2002	**2003**	2002
	($ per thousand cubic feet)		*($ per thousand cubic feet)*		*($ per barrel)*	
Price, net of transportation and selling	**$ 6.43**	$ 4.23	**$ 6.13**	$ 3.56	**$ 31.45**	$ 29.92
Royalties	**1.05**	0.65	**1.74**	0.98	**6.13**	4.69
Operating expenses	**0.54**	0.54	**0.33**	0.38	**–**	–
Netback excluding hedging	**4.84**	3.04	**4.06**	2.20	**25.32**	25.23
Financial Hedge	**(0.31)**	(0.12)	**(0.24)**	0.06	**–**	–
Netback including hedging	**$ 4.53**	$ 2.92	**$ 3.82**	$ 2.26	**$ 25.32**	$ 25.23
	(Mmcf/d)		*(Mmcf/d)*		*(bbls/d)*	
Sales Volumes	**2,213**	2,144	**698**	428	**30,299**	23,911

Six Months Ended June 30	Produced Gas - Canada		Produced Gas - U.S.		NGLs - North America	
	2003	2002	**2003**	2002	**2003**	2002
	($ per thousand cubic feet)		*($ per thousand cubic feet)*		*($ per barrel)*	
Price, net of transportation and selling	**$ 7.16**	$ 3.91	**$ 6.82**	$ 3.59	**$ 37.41**	$ 26.09
Royalties	**1.03**	0.54	**1.98**	0.99	**7.62**	3.26
Operating expenses	**0.59**	0.52	**0.29**	0.44	**–**	–
Netback excluding hedging	**5.54**	2.85	**4.55**	2.16	**29.79**	22.83
Financial Hedge	**(0.49)**	0.02	**0.27**	0.05	**–**	–
Netback including hedging	**$ 5.05**	$ 2.87	**$ 4.82**	$ 2.21	**$ 29.79**	$ 22.83
	(Mmcf/d)		*(Mmcf/d)*		*(bbls/d)*	
Sales Volumes	**2,271**	1,576	**685**	251	**29,610**	19,637

Gross revenue from sales of produced gas and NGLs was $1,820 million in the second quarter of 2003, an increase of $684 million, or 60 percent over the same quarter last year. Increased sales volumes and higher natural gas and NGLs commodity prices were contributing factors to the increase in gross revenue. Natural gas revenue in the quarter included a cost of $78 million from financial currency and commodity hedging activities, which compared with a cost of $20 million in the second quarter of 2002.

In the first six months of 2003, gross revenue from sales of produced gas and NGLs was $4,078 million, an increase of $2,544 million, or 166 percent, over the corresponding period last year. The increase in 2003 results reflected higher sales volumes and commodity prices as well as the inclusion of post-merger results for the full six-month period. A cost of $167 million from financial currency and commodity hedging was included in natural gas and NGLs gross revenue. This compared with a net gain of $9 million on financial transactions in the first six months of last year.

Produced gas sales volumes in the quarter averaged 2,923 million cubic feet per day, up 13 percent from sales of 2,580 million cubic feet per day in the second quarter of last year. NGLs sales volumes were 30,917 barrels per day, up 22 percent from sales volumes of 25,324 barrels per day in the corresponding quarter of 2002. The higher 2003 sales volumes were primarily the result of acquisitions by subsidiaries in the U.S. Rockies region and continued development successes at Jonah, Mamm Creek, Suffield, the Palliser Block and Greater Sierra.

In the first half of the year produced gas sales volumes rose to 2,968 million cubic feet per day, a 62 percent increase over 2002 levels for the same period. NGLs sales volumes were also higher at 30,487 barrels per day compared to sales volumes of 20,929 barrels per day in the first six months of 2002. In addition to the acquisitions in the U.S. Rockies region and continued development previously mentioned, the increase in the year-to-date sales volumes also reflected the added post-merger volumes for the full first half of the year.

In addition to growth in the Company's natural gas and NGLs sales volumes, gross revenue also benefited from stronger commodity prices. Realized natural gas sales prices in Canada averaged $6.43 per thousand cubic feet in the quarter, a 52 percent improvement over an average price of $4.23 per thousand cubic feet in the second quarter of 2002. The realized price for natural gas in the U.S. was also higher at $6.13 per thousand cubic feet, an increase of 72 percent over $3.56 per thousand cubic feet in the same quarter last year. The average NGLs price for the quarter was $31.45 per barrel, up five percent from $29.92 per barrel in the second quarter of 2002.

High commodity prices resulted in stronger realized natural gas and NGLs prices on a year-to-date basis. The realized Canadian natural gas sales price averaged $7.16 per thousand cubic feet compared to an average price of $3.91 per thousand cubic feet in the first six months of 2002. The realized price for natural gas in the U.S. was $6.82 per thousand cubic feet, which compared with $3.59 per thousand cubic feet in the first six months of 2002. The average NGLs price for the year to date was up 43 percent to $37.41 per barrel.

Produced gas operating expenses in Canada, net of operating recoveries, in the quarter were $0.54 per thousand cubic feet, unchanged from the same quarter of 2002, and down from $0.63 per thousand cubic feet in the first quarter of 2003. For the year to date, these costs were $0.59 per thousand cubic feet, which compared with $0.52 per thousand cubic feet in the same period last year. Higher Canadian operating costs, year over year, resulted from increased maintenance, workovers and electrical costs, higher processing fees and increased production from higher operating cost properties.

In the U.S. Rockies, produced gas operating expenses, net of operating recoveries, averaged $0.33 per thousand cubic feet in the second quarter of 2003, an improvement over costs of $0.38 per thousand cubic feet in the same quarter of 2002. For the six months ended June 30, 2003, these costs were $0.29 per thousand cubic feet, down 34 percent from $0.44 per thousand cubic feet in the same period last year. Year-over-year unit operating costs in the U.S. benefited from the addition of lower operating cost properties at Jonah and Mamm Creek.

Crude Oil

Per-Unit Results - Crude Oil

Three Months Ended June 30	North America		Ecuador		United Kingdom	
($ per barrel)	**2003**	2002	**2003**	2002	**2003**	2002
Price, net of transportation and selling	**$ 29.80**	$ 30,82	**$ 29.50**	$ 31.67	**$ 35.58**	$ 37.78
Royalties	**3.67**	3.68	**9.78**	10.76	**–**	–
Operating expenses	**7.53**	6.51	**5.91**	5.70	**6.56**	3.12
Netback excluding hedging	**18.60**	20.63	**13.81**	15.21	**29.02**	34.66
Financial Hedge	**(3.08)**	(1.15)	**–**	(0.04)	**–**	–
Netback including hedging	**$ 15.52**	$ 19.48	**$ 13.81**	$ 15.17	**$ 29.02**	$ 34.66
Sales Volumes *(bbls/d)*	**150,951**	143,040	**49,575**	59,864	**8,401**	10,553

Six Months Ended June 30	North America		Ecuador		United Kingdom	
($ per barrel)	**2003**	2002	**2003**	2002	**2003**	2002
Price, net of transportation and selling	**$ 32.70**	$ 28.74	**$ 36.13**	$ 31.67	**$ 39.25**	$ 34.31
Royalties	**4.19**	3.83	**13.16**	10.76	**–**	–
Operating expenses	**7.56**	6.49	**5.78**	5.70	**5.43**	2.97
Netback excluding hedging	**20.95**	18.42	**17.19**	15.21	**33.82**	31.34
Financial Hedge	**(5.94)**	(1.05)	**–**	(0.04)	**–**	(0.16)
Netback including hedging	**$ 15.01**	$ 17.37	**$ 17.19**	$ 15.17	**$ 33.82**	$ 31.18
Sales Volumes *(bbls/d)*	**150,917**	115,998	**46,189**	30,097	**8,933**	11,133

In the second quarter of 2003, gross revenue from the sale of crude oil was $569 million, down 8 percent from $618 million in the same quarter last year. The decline in gross revenue was the result of lower realized prices and an increase in costs related to financial hedging. Crude oil gross revenue in the quarter was reduced by a cost of approximately $42 million resulting from financial commodity and currency hedging. This compared with a cost of $15 million in the second quarter of 2002.

Gross revenue from the sale of crude oil for the first six months of 2003 was $1,182 million, an increase of 38 percent over gross revenue of $858 million for the same period last year. The increase reflected higher average realized sales prices and an overall increase in oil sales volumes which was mainly the result of increased production from the Company's SAGD projects and the inclusion of post-merger volumes for the full six month period. Crude oil gross revenue in the first six months of 2003 was reduced by approximately $162 million as a result of financial commodity and currency hedging, which compared with a reduction of $22 million in the same period of 2002.

North America crude oil sales rose six percent, averaging 150,951 barrels per day in the quarter, compared with sales of 143,040 barrels per day in the same quarter of 2002. The increase in sales volumes reflected continued development at Suffield and Pelican Lake, commencement of commercial production at Christina Lake and increased production at Foster Creek, which is now producing at design capacity of 20,000 barrels per day.

North America crude oil sales were also higher on a year-to-date basis, averaging 150,917 barrels per day in 2003 compared with 115,998 barrels per day in the first six months of 2002. The improvement in sales reflected the increase in volumes related to the Company's SAGD projects, continued development at Suffield, as well as the inclusion of the full six months of post-merger sales volumes in 2003.

World oil prices continued to be strong in the first six months of 2003. The Company's realized price from North America crude oil averaged $29.80 per barrel in the quarter and $32.70 per barrel in the first six months of 2003. This compared with realized prices of $30.82 per barrel and $28.74 per barrel in the respective periods of 2002.

In the second quarter of 2003, unit operating costs for North America crude oil averaged $7.53 per barrel, up 16 percent from $6.51 per barrel in the second quarter of 2002 and down slightly from $7.59 per barrel in the first quarter of 2003. For the six months ended June 30, 2003, these costs averaged $7.56 per barrel compared with an average cost of $6.49 per barrel in the same period of 2002. The higher unit operating expenses in 2003 were due to increased production from the SAGD projects at Foster Creek and Christina Lake, higher maintenance costs and higher fuel and electricity costs resulting from the rise in natural gas prices.

Crude oil production in Ecuador averaged 49,006 barrels per day during the quarter, down from 52,744 barrels per day in the same quarter of 2002. In the second quarter of 2003, the Company continued to transfer crude oil to the Oleoducto de Crudos Pesados ("OCP") with 2,816 barrels per day of crude oil being transferred for use by OCP in asset commissioning. The transfer of crude oil to the OCP pipeline for asset commissioning is also expected in the third quarter of 2003. Sales of Ecuador crude oil were 49,575 barrels per day, including an overlifting of 3,385 barrels per day, which compared with sales of 59,864 barrels per day in the second quarter of last year. Last year's second quarter sales volumes included an overlifting of 7,120 barrels. Sales during the second quarter of 2003 were negatively impacted by a transportation interruption on Ecuador's main export pipeline, the SOTE, and a lack of light crude oil required for blending with heavy oil for the appropriate SOTE pipeline mix. Sales of Ecuador crude oil were higher on a year to date basis over 2002 as a result of the inclusion of a full six months of volumes in 2003.

The average realized price for Ecuador crude oil was $29.50 per barrel in the quarter and $36.13 per barrel for the year to date which compared to an average price of $31.67 per barrel for both the second quarter and the first six months of last year. Unit operating costs were $5.91 per barrel in the quarter, up slightly from $5.70 per barrel in the second quarter of 2002. These costs were $5.78 per barrel in the first six months of the year compared with $5.70 per barrel in the same period last year.

Sales of U.K. crude oil averaged 8,401 barrels per day in the quarter and 8,933 barrels per day for the year to date, which compared with sales of 10,553 barrels per day and 11,133 barrels per day in the respective periods last year. Production declines were expected due to the natural declines of the fields and resulted in an increase in per unit operating costs, which were $6.56 per barrel in the quarter and $5.43 per barrel for the year to date. In comparison, 2002 unit operating costs were $3.12 per barrel in the second quarter and $2.97 per barrel for the six months ended June 30.

Midstream & Marketing

Midstream Financial Results*	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2003**	2002	**2003**	2002
Gross Revenue	**$ 211**	157	**$ 692**	$ 230
Expenses				
Operating	**73**	78	193	133
Purchased product	**150**	51	458	51
Depreciation, depletion and amortization	**10**	20	**17**	24
	$ (22)	$ 8	**$ 24**	$ 22

* Results of the Midstream & Marketing segment exclude financial results related to discontinued operations as described in Note 4 to the Consolidated Financial Statements.

Gross revenue from continuing midstream operations increased to $211 million in the quarter, up from $157 million in same quarter of 2002 due primarily to higher commodity prices. Despite higher gross revenue, 2003 second quarter financial results were negatively impacted by lower margins and other short-term commodity price factors. Gas storage operations and optimization activities were adversely affected by narrow summer/winter gas price spreads. Relatively higher feedstock prices and typically reduced seasonal demand for propane decreased natural gas processing margins.

Marketing Financial Results* - by product

Three Months Ended June 30 *($ millions)*	Gas		Crude Oil & NGLs		Total	
	2003	2002	**2003**	2002	**2003**	2002
Gross Revenue	**$ 503**	$ 437	**$ 459**	$ 497	**$ 962**	$ 934
Expenses						
Transportation and selling	**4**	26	**17**	24	**21**	50
Operating	**40**	–	**3**	–	**43**	–
Purchased product	**485**	374	**441**	471	**926**	845
Depreciation, depletion and amortization	**–**	6	**–**	–	**–**	6
	$ (26)	$ 31	**$ (2)**	$ 2	**$ (28)**	$ 33

Six Months Ended June 30 *($ millions)*	Gas		Crude Oil & NGLs		Total	
	2003	2002	**2003**	2002	**2003**	2002
Gross Revenue	**$ 1,191**	$ 457	**$ 941**	$ 883	**$ 2,132**	$ 1,340
Expenses						
Transportation and selling	**8**	26	**40**	29	**48**	55
Operating	**58**	–	**7**	6	**65**	6
Purchased product	**1,155**	413	**890**	812	**2,045**	1,225
Depreciation, depletion and amortization	**1**	7	**–**	–	**1**	7
	$ (31)	$ 11	**$ 4**	$ 36	**$ (27)**	$ 47

* Results of the Midstream & Marketing segment exclude financial results related to discontinued operations as described in Note 4 to the Consolidated Financial Statements.

EnCana's Marketing operations include optimization activity to maximize value from the Company's assets and transportation commitments not utilized for its own production. During the second quarter of 2003, gross revenue was $962 million, up slightly from gross revenue of $934 million in the same quarter last year. For the six months ended June 30, 2003, gross revenue from the Company's marketing activity was up $792 million to $2,132 million over the same period of last year. This increase largely reflected the inclusion of a full six months of AEC volumes and the higher commodity prices experienced across the energy industry in the first half of 2003.

Corporate

Administrative expenses totalled $60 million in the quarter and $116 million for the year to date. This compared with $44 million and $61 million in the respective periods of 2002. The increase reflected the inclusion of the full six months of post-merger operations. In 2003, the Company has incurred higher insurance and governance costs. On a per unit basis, administrative costs were $0.91 per barrel of oil equivalent in the quarter compared with $0.72 per barrel of oil equivalent in the second quarter of last year. For the first six months these costs were $0.88 per barrel of oil equivalent which compared to $0.70 per barrel of oil equivalent in the first half of last year.

Net interest expense of $84 million was down from $103 million in the second quarter of 2002. The lower interest expense reflected lower debt levels in the second quarter of 2003. For the first six months of the year, net interest expense amounted to $170 million, which compared with $130 million in the first half of 2002. The higher six-month net interest expense resulted primarily from the additional interest expense associated with the comparatively higher average debt outstanding during the first six months of 2003.

A foreign exchange gain of $241 million was recorded in the second quarter of 2003. This compared with a gain of $170 million in the corresponding quarter of last year. A foreign exchange gain of $535 million was included in the Company's results for the first half of the year, which compared with a gain of $180 in the same period of 2002. The majority of the foreign exchange impact resulted from the translation of U.S. dollar denominated debt into Canadian dollars at the period-end exchange rate. Any exchange gains and losses resulting from this translation are recorded in earnings in the period they arise.

The provision for income tax resulted in a recovery of $202 million in the quarter, and an expense of $235 million for the year to date. This compared to expenses of $153 million and $235 million in the respective periods of 2002. The 2003 provision for the quarter included a $486 million decrease in future income tax liabilities resulting from the reductions in the Canadian federal and Alberta corporate income tax rates and related changes to the resource allowance deduction. These changes were substantively enacted during the quarter. The federal tax rate, which was reduced in other industries in 2000, is to be reduced by seven percentage points over the period 2003-2007, in addition the resource allowance deduction is to be phased out and replaced with a deduction for crown royalties paid, over the same period. The Alberta tax rate was reduced by one half of one percentage point. The effective tax rate for 2003 is expected to be 34 to 36 percent before considering the effect of the reduction in Canadian and Alberta tax rates and the unrealized gain or loss on the translation of U.S. dollar debt. The current tax recovery was $71 million for the quarter and $37 million for the six months ended June 30, 2003. The current tax provision for 2003 is expected to be in the range of $100 million to $125 million.

LIQUIDITY AND CAPITAL RESOURCES

Second quarter cash flow from continuing operations was $1,483 million, up from $904 million in the same quarter of 2002. Cash flow from continuing operations for the first half of 2003 was $3,290 million, $1,999 million higher than $1,291 million for the same period last year. The increased cash flow from continuing operations was primarily the result of higher revenues resulting from the Company’s growth in sales volumes and stronger commodity prices. Cash flow in the first half of 2003 was also impacted by the inclusion of the full six months of post-merger results.

EnCana’s net debt, including preferred securities, was $5,666 million at June 30, 2003 compared with $6,130 million at December 31, 2002. This decrease reflected the repayment of revolving credit and term loan borrowings and U.S. unsecured notes and debentures. The repayment of debt was funded in part by proceeds from the dispositions of the Syncrude interest and interests in the Cold Lake and Express Pipeline Systems. The strengthening of the Canadian dollar relative to the U.S. dollar, which resulted in an unrealized year-to-date gain of $493 million, before tax, on the translation of U.S. dollar debt, also contributed to the lower level of debt at June 30, 2003.

Net debt to capitalization, including all preferred securities as debt, was 28 percent, down from 31 percent at December 31, 2002. Net debt to EBITDA was 0.9 times the trailing 12-month cash flow at the end of the quarter. As at June 30, 2003, the Company had available unused committed bank credit facilities in the amount of $2,743 million.

At December 31, 2002, the Company had $457 million in preferred securities of a subsidiary recorded as a liability on its balance sheet. These preferred securities are unsecured junior subordinated debentures and were recorded as a liability of the Company following the merger with AEC. On January 1, 2003, these preferred securities became the direct obligation of EnCana as a result of the amalgamation of the Company with AEC and accordingly are now recorded under the shareholders’ equity section of the Consolidated Balance Sheet.

In October 2002, the Company received regulatory approval to make a Normal Course Issuer Bid. Under the bid, EnCana may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the approximately 476,871,300 Common Shares then outstanding. Purchases under the program must terminate on October 21, 2003 or on such earlier date as the Company may complete its purchases pursuant to the Notice of Intention filed with the Toronto Stock Exchange. During the second quarter, the Company purchased and paid for 3,342,900

Common Shares at an average price of $50.34 per Common Share. As of July 28, 2003, the Company had purchased for cancellation a total of 7,112,800 Common Shares at an average price of $50.38 per Common Share under this program.

Capital Expenditures

The Company's consolidated capital expenditures were $1,505 million in the quarter, up $115 million from the second quarter of 2002. Capital expenditures for the first half of the year of $3,031 million, accounted for more than half of the Company's forecast 2003 capital spending of $5 to $5.4 billion in core programs and compared with expenditures of $1,871 million in the first half of 2002. The majority of expenditures in both 2003 and 2002 were directed towards natural gas exploration and development in North America. The Company's capital investment for the quarter and the year to date was funded by cash flow and proceeds received on the dispositions of the Syncrude interest and interests in the Cold Lake and Express Pipeline Systems.

The following table provides a summary of the Company's capital spending, excluding dispositions and corporate acquisitions, on a divisional basis:

Capital Expenditures*	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2003**	2002	**2003**	2002
Upstream				
Canada	**$ 944**	$ 699	**$ 2,012**	$ 1,047
United States	**274**	537	**501**	624
Ecuador	**47**	72	**157**	72
U.K.	**14**	23	**38**	62
Other Countries	**43**	36	**68**	39
Total Upstream	**1,322**	1,367	**2,776**	1,844
Midstream & Marketing	**156**	16	**210**	17
Corporate	**27**	7	**45**	10
Total	**$ 1,505**	$ 1,390	**$ 3,031**	$ 1,871

* The above table excludes cash proceeds on dispostions of approximately $2 billion.

Upstream Capital Expenditures

Upstream capital expenditures totalled $1,322 million in the second quarter of 2003, down from $1,367 million in the same quarter last year. Capital spending on the Company's upstream operations for the year to date was $2,776 million, up from $1,844 million in the first half of 2002. The majority of 2003 expenditures related to North American properties, with spending in Canada directed primarily towards exploration and development of natural gas properties at Suffield and the Palliser Block in Alberta and Greater Sierra in northeast British Columbia. Capital expenditures in the United States focused primarily on natural gas exploration and development at Jonah and Mamm Creek. In addition, the Company bought out approximately $215 million in certain equipment operating leases during the quarter.

Midstream & Marketing Capital Expenditures

In the first half of 2003, capital expenditures in the Midstream and Marketing segment were $210 million, of which $156 million was spent during the second quarter. This compared with $17 million in the first half of 2002. Expenditures in the first six months of 2003 related primarily to ongoing improvements to midstream facilities, the construction of the Countess gas storage facility and the expansion of the Wild Goose storage facility. Year-to-date capital spending also included approximately $70 million related to equipment operating lease buyouts. The Company has started gas injections into the first 10 billion cubic feet of new storage capacity at Countess. The second phase of the Countess storage facility is expected to take total capacity to about 40 billion cubic feet by the second quarter of 2005. The expansion of the Wild Goose storage facility is expected to increase withdrawal capability from 200 million cubic feet per day to 450 million cubic feet per day in November 2003. By April 2004, gas storage capacity at the facility is planned to increase from 14 billion to approximately 24 billion cubic feet, while injection capacity is expected to rise from 80 million to 450 million cubic feet per day. In early July, a subsidiary of the Company increased its equity interest in the OCP pipeline in Ecuador from 31.4 percent to 36.3 percent. The OCP pipeline commissioning is on target for completion by the end of the third quarter of 2003.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company and its subsidiaries have entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements as outlined in the December 31, 2002 audited Consolidated Financial Statements and MD&A. As of June 30, 2003, these commitments, excluding debt obligations and preferred securities, had decreased by approximately $2 billion to approximately $6 billion. The reduction in commitments reflects the impact of the sale of the Syncrude interest, the strengthening of the U.S./Canadian dollar exchange rate, and the buyout of several equipment leases.

Discontinued Merchant Energy Operations

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

In addition to the previously disclosed action filed by E. & J. Gallo Winery, in the United States District Court in California, the Company and WD, along with other energy companies, have been named as defendants in seven class action lawsuits in California state court. These lawsuits relate to sales of natural gas in California from 1999 to the present and contain essentially similar 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 indexes and wash trading. The Gallo complaint claims damages in excess of US$30 million, before potential trebling under California laws. As is customary, the class actions do not 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 whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position.

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. These exposures are managed through the use of various derivative instruments and contracts, which are governed under formal policies approved by the Board of Directors, and are subject to limits established by the Board of Directors.

This risk management program is designed to enhance shareholder value by mitigating the volatility associated with commodity prices, exchange rates and interest rates and enhancing the probability of achieving corporate performance targets.

As a means of managing commodity price volatility in its producing areas and to ensure greater certainty in cash flow generation for its capital program, the Company has entered into various financial agreements and physical contracts. These transactions have fixed the oil and natural gas prices for a portion of the Company's future production.

Natural Gas

EnCana entered into fixed price AECO and NYMEX swaps and AECO and NYMEX collars as a means of protecting corporate cash flow to ensure sufficient funds for capital expenditure programs. To protect against weakening production area prices EnCana has entered into AECO and U.S. Rockies basis transactions. AECO production area prices may be negatively impacted as large amounts of contracted capacity on pipelines moving gas to downstream markets come up for renewal over the next several years. To manage exposure to transportation capacity on the Alliance Pipeline, the Company has entered into fixed price purchase and sale contracts.

Crude Oil

The Company has managed the WTI NYMEX price for a portion of its oil production with fixed price swaps and costless collars.

Gas Storage Optimization

As part of the Company's gas storage optimization program, the Company has entered into financial instruments and physical contracts at various locations and terms over the next 9 months to manage the price volatility of the corresponding physical transactions and inventory. The financial instruments used included futures, fixed for floating swaps and basis swaps.

The following table summarizes the unrecognized gains/(losses) on the Company's risk management activities at June 30, 2003:

	Contract Maturity			
($ millions)	2003	2004	2005 -2007	Total
Natural Gas	$ (74)	$ 115	$ 170	**$ 211**
Crude Oil	(92)	(148)	–	**(240)**
Gas Storage Optimization	22	10	–	**32**
Power	5	1	(1)	**5**
Foreign Currency Risk	36	3	–	**39**
Interest Rate Risk	11	27	27	**65**
Total	$ (92)	$ 8	$ 196	**$ 112**

Further details regarding the above risk management activities can be found in Note 10 to the Consolidated Financial Statements.

OUTLOOK

EnCana plans to continue to focus on growing natural gas production and storage capacity in North America and crude oil production in Canada and Ecuador to deliver near term growth while building the U.K. central North Sea and the Gulf of Mexico oil growth platforms for expected medium and longer term growth. The Company also plans to continue its efforts to expand its medium and long-term growth prospects by searching for new growth platforms through new ventures exploration.

The Company's 2003 forecast for produced gas sales remains at between 3.0 and 3.1 billion cubic feet per day. Crude oil and natural gas liquids sales volumes continue to be forecast at between 240,000 and 280,000 barrels per day.

The Company continues to expect average natural gas prices in 2003 to be higher than 2002 levels. Strong storage injection requirements in 2003 combined with reduced U.S. and Canadian supply have tightened the balance between supply and demand resulting in higher average natural gas prices in 2003.

Volatility in crude oil prices is expected to continue in 2003 as a result of market uncertainties over the reintegration of Iraqi production, political issues in Venezuela and Nigeria, OPEC compliance with production quotas, and the overall health of the world economies.

The Company expects 2003 capital investment in core programs to be approximately $5 to $5.4 billion before acquisitions and dispositions ($2.5 to $2.9 billion net of dispositions). It is anticipated that the capital program will be funded from cash flow and proceeds from the dispositions of non-core assets.

EnCana has issued guidance with respect to its 2004 operations forecasting crude oil and natural gas sales volumes of between 805,000 and 885,000 barrels of oil equivalent per day. This forecast is comprised of between 3,250 and 3,450 million cubic feet per day of natural gas sales and 265,000 to 310,000 barrels per day of sales of oil and natural gas liquids.

July 28, 2003

CONSOLIDATED STATEMENT OF EARNINGS

For the period ended June 30, 2003

		June 30			
		Three Months Ended		Six Months Ended	
(unaudited) ($ millions, except per share amounts)		**2003**	2002	**2003**	2002
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	*(Note 3)*	**$ 3,194**	$ 2,586	**$ 7,262**	$ 3,647
EXPENSES	*(Note 3)*				
Transportation and selling		**175**	157	**364**	206
Operating		**454**	348	**927**	519
Purchased product		**1,076**	896	**2,503**	1,276
Administrative		**60**	44	**116**	61
Interest, net		**84**	103	**170**	130
Foreign exchange (gain)	*(Note 5)*	**(241)**	(170)	**(535)**	(180)
Depreciation, depletion and amortization		**725**	573	**1,463**	787
		2,333	1,951	**5,008**	2,799
NET EARNINGS BEFORE THE UNDERNOTED		**861**	635	**2,254**	848
Income tax (recovery) expense	*(Note 6)*	**(202)**	153	**235**	235
NET EARNINGS FROM CONTINUING OPERATIONS		**1,063**	482	**2,019**	613
NET EARNINGS (LOSS) FROM DISCONTINUED OPERATIONS	*(Note 4)*	**3**	(24)	**293**	(22)
NET EARNINGS		**$ 1,066**	$ 458	**$ 2,312**	$ 591
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX		**(9)**	1	**(15)**	$ 1
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS		**$ 1,075**	$ 457	**$ 2,327**	$ 590
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 9)*				
Basic		**$ 2.23**	$ 1.04	**$ 4.23**	$ 1.71
Diluted		**$ 2.20**	$ 1.02	**$ 4.19**	$ 1.68
NET EARNINGS PER COMMON SHARE	*(Note 9)*				
Basic		**$ 2.24**	$ 0.99	**$ 4.84**	$ 1.65
Diluted		**$ 2.21**	$ 0.97	**$ 4.79**	$ 1.62

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

		Six Months Ended June 30	
(unaudited) ($ millions)		**2003**	2002
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 4,684**	$ 3,630
Net Earnings		**2,312**	591
Dividends on Common Shares and Other Distributions, net of tax		**(81)**	(74)
Charges for Normal Course Issuer Bid	*(Note 8)*	**(15)**	–
RETAINED EARNINGS, END OF PERIOD		**$ 6,900**	$ 4,147

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED BALANCE SHEET

For the period ended June 30, 2003

(unaudited) ($ millions)		**As at June 30, 2003**	As at Dec. 31, 2002
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 406**	$ 183
Accounts receivable and accrued revenue		**1,567**	1,987
Income tax receivable		**208**	–
Inventories		**652**	528
Assets of discontinued operations	*(Note 4)*	**571**	3,422
		3,404	6,120
Capital Assets, net	*(Note 3)*	**23,185**	22,356
Investments and Other Assets		**545**	377
Goodwill		**2,469**	2,469
	(Note 3)	**$ 29,603**	$ 31,322
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,109**	$ 2,282
Income tax payable		**–**	20
Liabilities of discontinued operations	*(Note 4)*	**140**	1,758
Current portion of long-term debt	*(Note 7)*	**150**	212
		2,399	4,272
Long-Term Debt	*(Note 7)*	**6,122**	7,395
Deferred Credits and Other Liabilities		**565**	564
Future Income Taxes		**5,161**	4,840
Preferred Securities of Subsidiary		**–**	457
		14,247	17,528
Shareholders' Equity			
Preferred securities		**549**	126
Share capital	*(Note 8)*	**8,791**	8,732
Share options, net		**102**	133
Paid in surplus		**–**	61
Retained earnings		**6,900**	4,684
Foreign currency translation adjustment		**(986)**	58
		15,356	13,794
		$ 29,603	$ 31,322

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

For the period ended June 30, 2003

		June 30			
		Three Months Ended		Six Months Ended	
(unaudited) ($ millions)		**2003**	2002	**2003**	2002
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 1,063**	$ 482	**$ 2,019**	$ 613
Depreciation, depletion and amortization		**725**	573	**1,463**	787
Future income taxes	*(Note 6)*	**(131)**	106	**272**	148
Other		**(174)**	(257)	**(464)**	(257)
Cash flow from continuing operations		**1,483**	904	**3,290**	1,291
Cash flow from discontinued operations		**(45)**	34	**–**	36
Cash flow		**1,438**	938	**3,290**	1,327
Net change in other assets and liabilities		**(17)**	–	**(23)**	–
Net change in non-cash working capital from continuing operations		**8**	(240)	**61**	(508)
Net change in non-cash working capital from discontinued operations		**65**	(11)	**82**	42
		1,494	687	**3,410**	861
INVESTING ACTIVITIES					
Business combination		**–**	(128)	**–**	(128)
Capital expenditures	*(Note 3)*	**(1,505)**	(1,390)	**(3,031)**	(1,871)
Proceeds on disposal of capital assets		**17**	240	**27**	243
Corporate acquisition	*(Note 2)*	**–**	–	**(179)**	–
Equity investments		**(122)**	–	**(188)**	–
Net change in investments and other		**(6)**	5	**(40)**	(12)
Net change in non-cash working capital from continuing operations		**(33)**	(219)	**(236)**	(250)
Discontinued operations		**(15)**	(69)	**1,948**	(69)
		(1,664)	(1,561)	**(1,699)**	(2,087)
FINANCING ACTIVITIES					
Net issuance (repayment) of long-term debt		**505**	572	**(840)**	492
Issuance of common shares	*(Note 8)*	**76**	51	**120**	69
Repurchase of common shares	*(Note 8)*	**(168)**	–	**(168)**	–
Dividends on common shares		**(48)**	(48)	**(96)**	(73)
Payments to preferred securities holders		**(4)**	(7)	**(12)**	(7)
Net change in non-cash working capital from continuing operations		**(3)**	2	**(8)**	(1)
Discontinued operations		**–**	(5)	**(438)**	(5)
Other		**(17)**	(32)	**(18)**	(32)
		341	533	**(1,460)**	443
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**25**	9	**28**	11
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**146**	(350)	**223**	(794)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**260**	503	**183**	947
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 406**	$ 153	**$ 406**	$ 153

See accompanying Notes to Consolidated Financial Statements.

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, 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, 2002. 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, 2002.

NOTE 2 CORPORATE ACQUISITION

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. for net cash consideration of $179 million (US$116 million). The purchase was accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the date of acquisition. The acquisition was accounted for as follows:

($ millions)	
Working Capital	$ 2
Capital Assets	194
Future Income Taxes	(17)
	$ 179

NOTE 3 SEGMENTED INFORMATION

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

- Upstream includes the Company's exploration for and production of natural gas, natural gas liquids and crude oil and related non-producing activities. The Company's Upstream operations are located in Canada, the United States, the U.K. central North Sea, Ecuador and International New Ventures exploration activity in the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia, Latin America, as well as, the Canadian East Coast and the North American northern frontier.
- Midstream & Marketing includes gas storage operations, natural gas liquids processing and power generation operations, as well as, marketing activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry.

Operations that have been discontinued are disclosed in Note 4.

SEGMENTED INFORMATION (continued)

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

	Upstream		Midstream & Marketing	
($ millions)	**2003**	2002	**2003**	2002
Revenues				
Gross revenue	**$ 2,453**	$ 1,773	**$ 1,173**	$ 1,091
Royalties and production taxes	**434**	281	**–**	–
Revenues, net of royalties and production taxes	**2,019**	1,492	**1,173**	1,091
Expenses				
Transportation and selling	**154**	107	**21**	50
Operating	**338**	270	**116**	78
Purchased product	**–**	–	**1,076**	896
Depreciation, depletion and amortization	**700**	535	**10**	26
Segment Income	**$ 827**	$ 580	**$ (50)**	$ 41

	Corporate		Consolidated	
	2003	2002	**2003**	2002
Revenues				
Gross revenue	**$ 2**	$ 3	**$ 3,628**	$ 2,867
Royalties and production taxes	**–**	–	**434**	281
Revenues, net of royalties and production taxes	**2**	3	**3,194**	2,586
Expenses				
Transportation and selling	**–**	–	**175**	157
Operating	**–**	–	**454**	348
Purchased product	**–**	–	**1,076**	896
Depreciation, depletion and amortization	**15**	12	**725**	573
Segment Income	**(13)**	(9)	**764**	612
Administrative	**60**	44	**60**	44
Interest, net	**84**	103	**84**	103
Foreign exchange (gain)	**(241)**	(170)	**(241)**	(170)
	(97)	(23)	**(97)**	(23)
Net Earnings Before Income Tax	**84**	14	**861**	635
Income tax (recovery) expense	**(202)**	153	**(202)**	153
Net Earnings from Continuing Operations	**$ 286**	$ (139)	**$ 1,063**	$ 482

SEGMENTED INFORMATION (continued)

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

UPSTREAM *($ millions)*	North America					
	Produced Gas and NGLs					
	Canada		U.S. Rockies		Crude Oil	
	2003	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 1,376**	$ 954	**$ 440**	$ 175	**$ 396**	$ 398
Royalties and production taxes	**221**	132	**119**	42	**50**	48
Revenues, net of royalties and production taxes	**1,155**	822	**321**	133	**346**	350
Expenses						
Transportation and selling	**86**	57	**26**	25	**26**	10
Operating	**121**	107	**22**	15	**107**	84
Depreciation, depletion and amortization	**385**	290	**94**	75	**150**	107
Segment Income	**$ 563**	$ 368	**$ 179**	$ 18	**$ 63**	$ 149

	Ecuador		U.K. North Sea		Non-Producing		Total Upstream	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues								
Gross revenue	**$ 144**	182	**$ 33**	$ 45	**$ 64**	$ 19	**$ 2,453**	$ 1,773
Royalties and production taxes	**44**	59	**–**	–	**–**	–	**434**	281
Revenues, net of royalties and production taxes	**100**	123	**33**	45	**64**	19	**2,019**	1,492
Expenses								
Transportation and selling	**11**	10	**5**	5	**–**	–	**154**	107
Operating	**26**	31	**5**	3	**57**	30	**338**	270
Depreciation, depletion and amortization	**43**	51	**26**	9	**2**	3	**700**	535
Segment Income	**$ 20**	31	**$ (3)**	$ 28	**$ 5**	$ (14)	**$ 827**	$ 580

MIDSTREAM & MARKETING *($ millions)*	Midstream		Marketing*		Total Midstream & Marketing	
	2003	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 211**	$ 157	**$ 962**	$ 934	**$ 1,173**	$ 1,091
Expenses						
Transportation and selling	**–**	–	**21**	50	**21**	50
Operating	**73**	78	**43**	–	**116**	78
Purchased product	**150**	51	**926**	845	**1,076**	896
Depreciation, depletion and amortization	**10**	20	**–**	6	**10**	26
Segment Income	**$ (22)**	$ 8	**$ (28)**	$ 33	**$ (50)**	$ 41

* Includes activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

SEGMENTED INFORMATION (continued)

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

	Upstream		Midstream & Marketing	
($ millions)	**2003**	2002	**2003**	2002
Revenues				
Gross revenue	**$ 5,369**	$ 2,427	**$ 2,824**	$ 1,570
Royalties and production taxes	**933**	349	**–**	–
Revenues, net of royalties and production taxes	**4,436**	2,078	**2,824**	1,570
Expenses				
Transportation and selling	**316**	151	**48**	55
Operating	**669**	380	**258**	139
Purchased product	**–**	–	**2,503**	1,276
Depreciation, depletion and amortization	**1,420**	738	**18**	31
Segment Income	**$ 2,031**	$ 809	**$ (3)**	$ 69

	Corporate		Consolidated	
	2003	2002	**2003**	2002
Revenues				
Gross revenue	**$ 2**	$ (1)	**$ 8,195**	$ 3,996
Royalties and production taxes	**–**	–	**933**	349
Revenues, net of royalties and production taxes	**2**	(1)	**7,262**	3,647
Expenses				
Transportation and selling	**–**	–	**364**	206
Operating	**–**	–	**927**	519
Purchased product	**–**	–	**2,503**	1,276
Depreciation, depletion and amortization	**25**	18	**1,463**	787
Segment Income	**(23)**	(19)	**2,005**	859
Administrative	**116**	61	**116**	61
Interest, net	**170**	130	**170**	130
Foreign exchange (gain)	**(535)**	(180)	**(535)**	(180)
	(249)	11	**(249)**	11
Net Earnings Before Income Tax	**226**	(30)	**2,254**	848
Income tax expense	**235**	235	**235**	235
Net Earnings from Continuing Operations	**$ (9)**	$ (265)	**$ 2,019**	$ 613

SEGMENTED INFORMATION (continued)

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

UPSTREAM *($ millions)*	North America					
	Produced Gas and NGLs					
	Canada		U.S. Rockies		Crude Oil	
	2003	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 3,053**	$ 1,312	**$ 1,011**	$ 207	**$ 791**	$ 602
Royalties and production taxes	**445**	160	**263**	49	**115**	81
Revenues, net of royalties and production taxes	**2,608**	1,152	**748**	158	**676**	521
Expenses						
Transportation and selling	**178**	88	**49**	25	**57**	18
Operating	**256**	151	**37**	20	**209**	136
Depreciation, depletion and amortization	**787**	407	**194**	92	**297**	163
Segment Income	**$ 1,387**	$ 506	**$ 468**	$ 21	**$ 113**	$ 204

	Ecuador		U.K. North Sea		Non-Producing		Total Upstream	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues								
Gross revenue	**$ 323**	$ 182	**$ 82**	$ 89	**$ 109**	$ 35	**$ 5,369**	$ 2,427
Royalties and production taxes	**110**	59	**–**	–	**–**	–	**933**	349
Revenues, net of royalties and production taxes	**213**	123	**82**	89	**109**	35	**4,436**	2,078
Expenses								
Transportation and selling	**21**	10	**11**	10	**–**	–	**316**	151
Operating	**48**	31	**9**	6	**110**	36	**669**	380
Depreciation, depletion and amortization	**78**	51	**60**	19	**4**	6	**1,420**	738
Segment Income	**$ 66**	$ 31	**$ 2**	$ 54	**$ (5)**	$ (7)	**$ 2,031**	$ 809

MIDSTREAM & MARKETING *($ millions)*	Midstream		Marketing*		Total Midstream & Marketing	
	2003	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 692**	$ 230	**$ 2,132**	$ 1,340	**$ 2,824**	$ 1,570
Expenses						
Transportation and selling	**–**	–	**48**	55	**48**	55
Operating	**193**	133	**65**	6	**258**	139
Purchased product	**458**	51	**2,045**	1,225	**2,503**	1,276
Depreciation, depletion and amortization	**17**	24	**1**	7	**18**	31
Segment Income	**$ 24**	$ 22	**$ (27)**	$ 47	**$ (3)**	$ 69

* Includes activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

SEGMENTED INFORMATION (continued)

Capital Expenditures

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2003**	2002	**2003**	2002
Upstream				
Canada	**$ 944**	$ 699	**$ 2,012**	$ 1,047
United States	**274**	537	**501**	624
Ecuador	**47**	72	**157**	72
United Kingdom	**14**	23	**38**	62
Other Countries	**43**	36	**68**	39
Midstream & Marketing	**156**	16	**210**	17
Corporate	**27**	7	**45**	10
Total	**$ 1,505**	$ 1,390	**$ 3,031**	$ 1,871

Capital and Total Assets

	Capital Assets As at		Total Assets As at	
($ millions)	**June 30, 2003**	Dec. 31, 2002	**June 30, 2003**	Dec. 31, 2002
Upstream	**$ 22,061**	$ 21,422	**$ 23,392**	$ 25,192
Midstream & Marketing	**902**	742	**3,110**	2,216
Corporate	**222**	192	**2,530**	492
Assets of Discontinued Operations			**571**	3,422
Total	**$ 23,185**	$ 22,356	**$ 29,603**	$ 31,322

NOTE 4 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 $1,026 million plus closing adjustments. The Company also granted Canadian Oil Sands Limited an option to purchase its remaining 3.75 percent working interest in Syncrude and a gross-overriding royalty interest. On July 10, 2003 the Company completed the sale of the remaining interest in Syncrude for proceeds of $417 million, subject to closing adjustments. This transaction completes the Company's disposition of its interest in Syncrude and, as a result, these operations have been accounted for as discontinued operations. There was no gain or loss on this sale.

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which was included in the Midstream & Marketing segment. Accordingly, these operations have been accounted for as discontinued operations. The wind-down of these operations was substantially completed at December 31, 2002.

On July 9, 2002, the Company announced that it planned to sell its 70 percent equity investment in the Cold Lake Pipeline System and its 100 percent interest in the Express Pipeline System. Accordingly, these operations have been accounted for as discontinued operations. On January 2, 2003 and January 9, 2003, the Company completed the sale of its interest in the Cold Lake Pipeline System and Express Pipeline System for total consideration of approximately $1.6 billion, including assumption of related long-term debt, and recorded an after-tax gain on sale of $263 million.

DISCONTINUED OPERATIONS (continued)

The following table presents the effect of the discontinued operations on the Consolidated Financial Statements:

Consolidated Statement of Earnings

	For the three months ended June 30							
	Syncrude		Merchant Energy		Midstream - Pipelines		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues, net of royalties and production taxes	**$ 28**	$ 90	**$ –**	$ 563	**$ –**	$ 58	**$ 28**	$ 711
Expenses								
Transportation and selling	**1**	1	**–**	–	**–**	–	**1**	1
Operating	**20**	68	**–**	–	**–**	20	**20**	88
Purchased product	**–**	–	**–**	580	**–**	–	**–**	580
Administrative	**–**	–	**–**	8	**–**	–	**–**	8
Interest, net	**–**	–	**–**	–	**–**	11	**–**	11
Foreign exchange	**–**	–	**–**	–	**–**	(10)	**–**	(10)
Depletion, depreciation and amortization	**2**	7	**–**	1	**–**	11	**2**	19
Loss on discontinuance	**–**	–	**–**	53	**–**	–	**–**	53
	23	76	**–**	642	**–**	32	**23**	750
Net Earnings Before Income Tax	**5**	14	**–**	(79)	**–**	26	**5**	(39)
Income tax expense (recovery)	**2**	2	**–**	(28)	**–**	11	**2**	(15)
Net Earnings (Loss) from Discontinued Operations	**$ 3**	$ 12	**$ –**	$ (51)	**$ –**	$ 15	**$ 3**	$ (24)

Consolidated Statement of Earnings

	For the six months ended June 30							
	Syncrude*		Merchant Energy		Midstream - Pipelines*		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues, net of royalties and production taxes	**$ 118**	$ 90	**$ –**	$ 1,309	**$ –**	$ 58	**$ 118**	$ 1,457
Expenses								
Transportation and selling	**2**	1	**–**	–	**–**	–	**2**	1
Operating	**63**	68	**–**	–	**–**	20	**63**	88
Purchased product	**–**	–	**–**	1,313	**–**	–	**–**	1,313
Administrative	**–**	–	**–**	18	**–**	–	**–**	18
Interest, net	**–**	–	**–**	–	**–**	11	**–**	11
Foreign exchange	**–**	–	**–**	–	**–**	(10)	**–**	(10)
Depletion, depreciation and amortization	**9**	7	**–**	1	**–**	11	**9**	19
(Gain) loss on discontinuance	**–**	–	**–**	53	**(343)**	–	**(343)**	53
	74	76	**–**	1,385	**(343)**	32	**(269)**	1,493
Net Earnings Before Income Tax	**44**	14	**–**	(76)	**343**	26	**387**	(36)
Income tax expense (recovery)	**14**	2	**–**	(27)	**80**	11	**94**	(14)
Net Earnings (Loss) from Discontinued Operations	**$ 30**	$ 12	**$ –**	$ (49)	**$ 263**	$ 15	**$ 293**	$ (22)

* Reflects only three months of earnings for 2002 as EnCana did not, at that time, own the operations which have been discontinued.

DISCONTINUED OPERATIONS (continued)

Consolidated Balance Sheet

	As at June 30							
	Syncrude		Merchant Energy		Midstream - Pipelines		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Assets								
Cash and cash equivalents	**$ 8**	$ 14	**$ –**	$ –	**$ –**	$ 66	**$ 8**	$ 80
Accounts receivable and accrued revenue	**14**	27	**–**	338	**–**	44	**14**	409
Inventories	**4**	15	**–**	–	**–**	1	**4**	16
	26	56	**–**	338	**–**	111	**26**	505
Capital assets, net	**426**	1,273	**–**	–	**–**	807	**426**	2,080
Investments and other assets	**–**	–	**–**	–	**–**	417	**–**	417
Goodwill	**119**	417	**–**	–	**–**	191	**119**	608
	571	1,746	**–**	338	**–**	1,526	**571**	3,610
Liabilities								
Accounts payable and accrued liabilities	**21**	94	**–**	240	**–**	68	**21**	402
Income tax payable	**55**	6	**–**	–	**–**	4	**55**	10
Current portion of long-term debt	**–**	–	**–**	–	**–**	23	**–**	23
	76	100	**–**	240	**–**	95	**76**	435
Deferred credits and other liabilities	**6**	21	**–**	–	**–**	–	**6**	21
Long-term debt	**–**	–	**–**	–	**–**	567	**–**	567
Future income taxes	**58**	317	**–**	–	**–**	163	**58**	480
	140	438	**–**	240	**–**	825	**140**	1,503
Net Assets of Discontinued Operations	**$ 431**	$ 1,308	**$ –**	$ 98	**$ –**	$ 701	**$ 431**	$ 2,107

Consolidated Balance Sheet

	As at December 31	
($ millions)	2002	2001
Assets		
Cash and cash equivalents	$ 97	$ –
Accounts receivable and accrued revenue	96	632
Inventories	16	70
	209	702
Capital assets, net	2,231	9
Investments and other assets	374	17
Goodwill	608	–
	3,422	728
Liabilities		
Accounts payable and accrued liabilities	153	584
Income tax payable	11	–
Short-term debt	438	–
Current portion of long-term debt	23	–
	625	584
Long-term debt	576	–
Deferred credits and liabilities	21	2
Future income taxes	536	–
	1,758	586
Net Assets of Discontinued Operations	$ 1,664	$ 142

NOTE 5 FOREIGN EXCHANGE (GAIN)

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2003**	2002	**2003**	2002
Unrealized foreign exchange (gain) on translation of U.S. dollar debt	**$ (248)**	$ (192)	**$ (493)**	$ (194)
Other foreign exchange losses (gains)	**7**	22	**(42)**	14
	$ (241)	$ (170)	**$ (535)**	$ (180)

NOTE 6 INCOME TAXES

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2003**	2002	**2003**	2002
Provision for Income Taxes				
Current				
Canada	**$ (81)**	$ 27	**$ (59)**	$ 64
United States	**–**	8	**–**	8
Ecuador	**7**	7	**19**	7
United Kingdom	**3**	5	**3**	8
	(71)	47	**(37)**	87
Future	**355**	148	**758**	190
Future tax rate reductions *	**(486)**	(42)	**(486)**	(42)
	$ (202)	$ 153	**$ 235**	$ 235

* During the quarter both the Canadian federal and Alberta governments substantively enacted income tax rate reductions previously announced.

NOTE 7 LONG-TERM DEBT

($ millions)		**As at June 30, 2003**	As at Dec. 31, 2002
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings		**$ 1,043**	$ 1,388
Unsecured notes and debentures		**1,825**	1,825
		2,868	3,213
U.S. Dollar Denominated Debt			
U.S. revolving credit and term loan borrowings		**317**	696
U.S. unsecured notes and debentures		**2,999**	3,608
		3,316	4,304
Increase in Value of Debt Acquired	*(Note A)*	**88**	90
Current Portion of Long-term Debt		**(150)**	(212)
		$ 6,122	$ 7,395

A) Increase in Value of Debt Acquired

Certain of the notes and debentures of the Company were acquired in the business combination with Alberta Energy Company Ltd. on April 5, 2002 and were accounted for at their fair value at the date 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 24 years.

NOTE 8 SHARE CAPITAL

(millions)	June 30, 2003 Number	Amount	December 31, 2002 Number	Amount
Common Shares Outstanding, Beginning of Year	**478.9**	**$ 8,732**	254.9	$ 196
Shares Issued to AEC Shareholders	**–**	**–**	218.5	8,397
Shares Issued under Option Plans	**4.3**	**120**	5.5	139
Shares Repurchased	**(3.3)**	**(61)**	–	–
Common Shares Outstanding, End of Period	**479.9**	**$ 8,791**	478.9	$ 8,732

During the quarter, the Company purchased, for cancellation, 3,342,900 common shares for total consideration of approximately $168 million. Of the $168 million paid, $61 million was charged to Share capital, $92 million was charged to Paid in surplus and $15 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 plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous successor and/or related company replacement plans expire ten years from the date the options were granted.

The following tables summarize the information about options to purchase common shares at June 30, 2003:

	Stock Options *(millions)*	Weighted Average Exercise Price *($)*
Outstanding, Beginning of Year	**29.6**	**39.74**
Granted under EnCana Plans	**5.8**	**47.50**
Exercised	**(4.3)**	**28.09**
Forfeited	**(0.8)**	**47.34**
Outstanding, End of Period	**30.3**	**42.71**
Exercisable, End of Period	**16.4**	**38.29**

	Outstanding Options			**Exercisable Options**	
Range of Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *($)*
13.50 to 19.99	1.9	1.1	18.86	1.9	18.86
20.00 to 24.99	1.4	1.9	22.33	1.4	22.33
25.00 to 29.99	2.4	1.9	26.52	2.4	26.52
30.00 to 43.99	1.5	2.7	38.69	1.3	38.18
44.00 to 53.00	23.1	3.8	47.90	9.4	47.71
	30.3	2.9	42.71	16.4	38.29

SHARE CAPITAL (continued)

The Company does not record compensation expense in the Consolidated Financial Statements for share options granted to employees and directors. If the fair-value method had been used, the Company's Net Earnings and Net Earnings per Common Share would approximate the following pro forma amounts:

	Six Months Ended June 30	
($ millions, except per share amounts)	**2003**	2002
Compensation Costs	**33**	50
Net Earnings		
As reported	**2,312**	591
Pro forma	**2,279**	541
Net Earnings per Common Share		
Basic		
As reported	**4.84**	1.65
Pro forma	**4.78**	1.51
Diluted		
As reported	**4.79**	1.62
Pro forma	**4.72**	1.48

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:

	Six Months Ended June 30	
	2003	2002
Weighted Average Fair Value of Options Granted	**$ 12.18**	$ 13.40
Risk Free Interest Rate	**3.96%**	4.46%
Expected Lives (years)	**3.00**	3.00
Expected Volatility	**0.33**	0.35
Annual Dividend per Share	**$ 0.40**	$ 0.40

NOTE 9 PER SHARE AMOUNTS

The following table summarizes the common shares used in calculating net earnings per common share.

	Three Months Ended			Six Months Ended	
	March 31	June 30		June 30	
(millions)	**2003**	**2003**	2002	**2003**	2002
Weighted Average Common Shares Outstanding					
- Basic	**479.9**	**480.6**	461.1	**480.3**	358.2
Effect of Dilutive Securities	**7.0**	**6.3**	8.9	**6.0**	6.8
Weighted Average Common Shares Outstanding					
- Diluted	**486.9**	**486.9**	470.0	**486.3**	365.0

NOTE 10 FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Unrecognized gains (losses) on risk management activities are as follows:

($ millions)	**As at June 30, 2003**
Commodity Price Risk	
Natural gas	**$ 211**
Crude oil	**(240)**
Gas storage optimization	**32**
Power	**5**
Foreign Currency Risk	**39**
Interest Rate Risk	**65**
Unrecognized Gains	**$ 112**

Information with respect to foreign currency risk and interest rate risk contracts in place at December 31, 2002, is disclosed in Note 19 to the Company's annual audited Consolidated Financial Statements.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Natural Gas

At June 30, 2003, the fair value of financial instruments that related to the corporate gas risk management activities was $167 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Physical/ Financial	Term	Price		Unrecognized Gain/(Loss) *(Cdn$ millions)*
Fixed Price Contracts						
Sales Contracts						
Fixed AECO price	565	Financial	2003	6.36	Cdn$/mcf	$ (24)
Fixed AECO price	10	Financial	2003	3.37	US$/mmbtu	(4)
Fixed AECO price	5	Physical	2003	5.88	Cdn$/mcf	(1)
Fixed AECO price	10	Physical	2003	3.34	US$/mmbtu	(4)
NYMEX Fixed price*	526	Financial	2003	4.50	US$/mmbtu	(134)
NYMEX Collars	50	Physical	2003	2.46-4.90	US$/mmbtu	(10)
Alliance Pipeline Mitigation	27	Financial	2003	3.92	US$/mmbtu	(11)
Fixed AECO price	453	Financial	2004	6.20	Cdn$/mcf	10
AECO Collars	71	Financial	2004	5.34-7.52	Cdn$/mcf	1
NYMEX Fixed price*	291	Financial	2004	5.06	US$/mmbtu	(18)
Chicago Fixed price	40	Financial	2004	5.42	US$/mmbtu	3
NYMEX Collars	10	Financial	2004	4.60-6.55	US$/mmbtu	1
NYMEX Collars	50	Physical	2004	2.46-4.90	US$/mmbtu	(21)
NYMEX Collars	47	Physical	2005-2007	2.46-4.90	US$/mmbtu	(47)
Purchase Contracts						
Alliance Pipeline Mitigation	30	Physical	2003	3.24	Cdn$/mcf	18
Basis Contracts						
Sales Contracts						
Fixed NYMEX to AECO basis*	368	Financial	2003	(0.55)	US$/mmbtu	13
Fixed NYMEX to Rockies basis	220	Financial	2003	(0.49)	US$/mmbtu	18
Fixed NYMEX to Rockies basis	356	Physical	2003	(0.51)	US$/mmbtu	27
Fixed NYMEX to AECO basis*	271	Financial	2004	(0.50)	US$/mmbtu	32
Fixed NYMEX to Rockies basis	190	Financial	2004	(0.42)	US$/mmbtu	39
Fixed NYMEX to Rockies basis	343	Physical	2004	(0.46)	US$/mmbtu	64
Fixed NYMEX to AECO basis*	387	Financial	2005-2007	(0.59)	US$/mmbtu	81
Fixed NYMEX to Rockies basis	132	Financial	2005-2007	(0.44)	US$/mmbtu	50
Fixed NYMEX to Rockies basis	214	Physical	2005-2007	(0.43)	US$/mmbtu	84
						167
Gas Marketing Financial positions (1)						7
Gas Marketing Physical positions (1)						37
						$ 211

* Certain Fixed NYMEX to AECO basis and NYMEX Fixed price contracts have previously been combined and reported as Fixed AECO prices. They are now reclassified and reported separately.

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Crude Oil

As at June 30, 2003, the Company's corporate oil risk management activities had an unrecognized loss of $240 million. The contracts were as follows:

	Notional Volumes *(bbl/d)*	Term	Average Price *(US$/bbl)*	Unrecognized Gain/(Loss) *(Cdn$ millions)*
Fixed WTI NYMEX Price	85,000	2003	25.28	$ (77)
Fixed WTI NYMEX Price	62,500	2004	23.13	(88)
Collars on WTI NYMEX	40,000	2003	21.95-29.00	(15)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(60)
				$ (240)

Gas Storage Optimization

As part of the Company's gas storage optimization program, the Company has entered into financial instruments at various locations and terms over the next 9 months to manage the price volatility of the corresponding physical transactions and inventory.

As at June 30, 2003, the unrecognized gain was as follows:

	Notional Volumes *(bcf)*	Price *(US$/mcf)*	Unrecognized Gain/(Loss) *(Cdn$ millions)*
Purchases	171.9	5.68	$ (34)
Sales	198.1	5.81	53
			19
Physical Contracts			13
			$ 32

The unrecognized gain does not reflect unrealized gains on physical inventory in storage.

NOTE 11 RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2003.

Financial Statistics

(C$ millions, except per share amounts)	2003			2002		
	Year-to-date	Q2	Q1	Q4	Q3	Q2
Cash Flow	**3,290**	**1,438**	1,852	1,472	1,022	938
Per share – Basic	**6.85**	**2.99**	3.86	3.08	2.14	2.03
– Diluted	**6.77**	**2.95**	3.80	3.03	2.12	2.00
Net Earnings	**2,312**	**1,066**	1,246	429	204	458
Per share – Basic	**4.84**	**2.24**	2.61	0.90	0.43	0.99
– Diluted	**4.79**	**2.21**	2.57	0.88	0.42	0.97
Net Earnings from Continuing Operations	**2,019**	**1,063**	956	374	116	482
Per share – Basic	**4.23**	**2.23**	2.00	0.78	0.24	1.04
– Diluted	**4.19**	**2.20**	1.98	0.77	0.24	1.02
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt (after tax) *	**1,627**	**864**	763	364	261	319
Per share – Diluted	**3.38**	**1.79**	1.58	0.75	0.54	0.67
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt (after tax) and tax rate change gain	**1,141**	**378**	763	364	261	277
Per share – Diluted	**2.38**	**0.79**	1.58	0.75	0.54	0.58

Shares	2003			2002		
	Year-to-date	Q2	Q1	Q4	Q3	Q2
Common Shares Outstanding *(millions)*						
Average	**480.3**	**480.6**	479.9	477.9	476.8	461.1
Average Diluted	**486.3**	**486.9**	486.9	485.2	482.2	470.0
Price range *($ per share)*						
TSE – C$						
High	**53.09**	**53.09**	49.55	49.75	48.25	50.25
Low	**45.70**	**45.70**	46.06	41.75	38.05	43.62
Close	**51.70**	**51.70**	47.75	48.78	48.00	46.70
NYSE – US$						
High	**39.26**	**39.26**	33.39	32.10	31.35	32.20
Low	**29.92**	**31.04**	29.92	26.45	24.08	28.50
Close	**38.37**	**38.37**	32.36	31.10	30.10	30.60
Share volume traded *(millions)*	**217.3**	**107.2**	110.2	122.3	105.5	113.2
Share value traded *($ millions weekly average)*	**404.1**	**405.4**	402.9	418.3	366.3	412.6

Ratios	
Debt to Capitalization	**28%**
Return on Capital Employed	**16%**
Return on Common Equity	**21%**

* The Company is required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate with any resulting adjustments recorded in the Consolidated Statement of Earnings.

Financial Statistics (continued)

Net Capital Investment *($ millions)*	**2003**	Pro Forma 2002
Upstream		
Canada	**$ 1,755**	$ 1,403
U.S.	**485**	494
Ecuador	**157**	142
United Kingdom	**38**	62
Other	**68**	32
Property Acquisitions	**273**	473
Dispositions	**(27)**	(292)
Net Upstream	**2,749**	2,314
Midstream & Marketing		
Capital Expenditures	**210**	24
Dispositions	**–**	–
Net Midstream & Marketing	**210**	24
Corporate	**45**	14
Corporate Acquisitions	**179**	–
Net Capital Investment - Continuing Operations	**3,183**	2,352
Discontinued Operations	**(1,948)**	102
Total Net Capital Investment	**$ 1,235**	$ 2,454

EnCana Corporation

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the Period Ended June 30, 2003

Pro Forma Operating Statistics

Sales Volumes		**2003**			2002			
		Year-to-date	**Q2**	Q1	Q4	Q3	Q2	Q1*
Produced Gas *(MMcf/d)*								
Canada		**2,271**	**2,213**	2,331	2,375	2,129	2,144	2,348
United States		**685**	**698**	672	654	550	428	365
United Kingdom		**12**	**12**	13	8	9	8	11
		2,968	**2,923**	3,016	3,037	2,688	2,580	2,724
Oil and Natural Gas Liquids *(bbls/d)*								
North America								
Light and Medium Oil		**59,626**	**59,012**	60,246	62,369	65,345	66,807	70,914
Heavy Oil		**91,291**	**91,939**	90,636	86,019	80,797	76,233	68,846
Natural Gas Liquids								
Canada		**18,562**	**17,970**	19,162	19,121	16,225	16,796	17,448
United States		**11,048**	**12,329**	9,751	11,558	6,702	7,115	6,427
Total North America		**180,527**	**181,250**	179,795	179,067	169,069	166,951	163,635
Ecuador								
Production		**51,851**	**49,006**	54,726	48,486	52,344	52,744	50,351
Transferred to OCP pipeline	**	**(5,488)**	**(2,816)**	(8,191)	–	–	–	–
Over/(under) lifting		**(174)**	**3,385**	(3,771)	1,448	3,235	7,120	(11,577)
Ecuador Sales		**46,189**	**49,575**	42,764	49,934	55,579	59,864	38,774
United Kingdom		**9,810**	**9,019**	10,610	7,786	9,538	11,966	12,889
Total Oil and Natural Gas Liquids		**236,526**	**239,844**	233,169	236,787	234,186	238,781	215,298
Total *(boe/d)*		**731,193**	**727,011**	735,836	742,954	682,186	668,781	669,298
Syncrude		**13,792**	**7,383**	20,272	34,261	36,039	24,295	31,548

* Q1 2002 volumes have been presented on a pro forma basis.

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

Operating Statistics

Per-unit Results

	2003			2002		
	Year-to-date	Q2	Q1	Q4	Q3	Q2
Produced Gas - Canada *($/Mcf)*						
Price, net of transportation and selling	**7.16**	**6.43**	7.85	5.17	3.24	4.23
Royalties	**1.03**	**1.05**	1.00	0.77	0.39	0.65
Operating expenses	**0.59**	**0.54**	0.63	0.59	0.58	0.54
Netback excluding hedge	**5.54**	**4.84**	6.22	3.81	2.27	3.04
Financial Hedge	**(0.49)**	**(0.31)**	(0.65)	(0.08)	0.29	(0.12)
Netback including hedge	**5.05**	**4.53**	5.57	3.73	2.56	2.92
Produced Gas - United States *(C$/Mcf)*						
Price, net of transportation and selling	**6.82**	**6.13**	7.55	4.74	3.16	3.56
Royalties	**1.98**	**1.74**	2.23	1.42	0.99	0.98
Operating expenses	**0.29**	**0.33**	0.25	0.28	0.34	0.38
Netback excluding hedge	**4.55**	**4.06**	5.07	3.04	1.83	2.20
Financial Hedge	**0.27**	**(0.24)**	0.80	0.42	0.57	0.06
Netback including hedge	**4.82**	**3.82**	5.87	3.46	2.40	2.26
Light and Medium Oil *($/bbl)*						
Price, net of transportation and selling	**38.58**	**35.81**	41.36	36.36	36.01	35.35
Royalties	**5.08**	**4.33**	5.82	4.81	4.56	4.36
Operating expenses	**7.61**	**7.54**	7.68	7.16	6.58	7.25
Netback excluding hedge	**25.89**	**23.94**	27.86	24.39	24.87	23.74
Financial Hedge	**(6.19)**	**(3.59)**	(8.83)	(1.26)	(0.89)	(1.59)
Netback including hedge	**19.70**	**20.35**	19.03	23.13	23.98	22.15
Heavy Oil *($/bbl)*						
Price, net of transportation and selling	**28.86**	**25.94**	31.80	25.81	29.44	26.85
Royalties	**3.61**	**3.25**	3.99	3.43	3.67	3.09
Operating expenses	**7.52**	**7.52**	7.52	5.64	6.71	5.87
Netback excluding hedge	**17.73**	**15.17**	20.29	16.74	19.06	17.89
Financial Hedge	**(5.78)**	**(2.74)**	(8.83)	(1.18)	(0.89)	(0.76)
Netback including hedge	**11.95**	**12.43**	11.46	15.56	18.17	17.13
Total Oil *($/bbl)*						
Price, net of transportation and selling	**32.70**	**29.80**	35.61	30.26	32.38	30.82
Royalties	**4.19**	**3.67**	4.72	4.01	4.07	3.68
Operating expenses	**7.56**	**7.53**	7.59	6.28	6.66	6.51
Netback excluding hedge	**20.95**	**18.60**	23.30	19.97	21.65	20.63
Financial Hedge	**(5.94)**	**(3.08)**	(8.83)	(1.22)	(0.89)	(1.15)
Netback including hedge	**15.01**	**15.52**	14.47	18.75	20.76	19.48
Natural Gas Liquids *($/bbl)*						
Price, net of transportation and selling	**37.41**	**31.45**	43.73	36.15	31.18	29.92
Royalties	**7.62**	**6.13**	9.21	5.95	4.62	4.69
Netback	**29.79**	**25.32**	34.52	30.20	26.56	25.23
Ecuador Oil *($/bbl)*						
Price, net of transportation and selling	**36.13**	**29.50**	43.90	35.38	33.59	31.67
Royalties	**13.16**	**9.78**	17.12	12.29	12.51	10.76
Operating expenses	**5.78**	**5.91**	5.63	6.04	4.60	5.70
Netback excluding hedge	**17.19**	**13.81**	21.15	17.05	16.48	15.21
Financial Hedge	**–**	**–**	–	–	–	(0.04)
Netback including hedge	**17.19**	**13.81**	21.15	17.05	16.48	15.17
United Kingdom Oil *($/bbl)*						
Price, net of transportation and selling	**39.25**	**35.58**	42.53	37.99	39.30	37.78
Operating expenses	**5.43**	**6.56**	4.41	11.10	5.71	3.12
Netback	**33.82**	**29.02**	38.12	26.89	33.59	34.66

EnCana Corporation

CONVENIENCE STATEMENTS

(Prepared in US$) For the Period Ended June 30, 2003

The Consolidated Financial Statements of the Company are prepared in Canadian dollars. The financial information presented below shows the Canadian GAAP financial information and has been translated into U.S. dollars for the convenience of the readers. The financial information presented below has been translated into U.S. dollars at a rate of $1 Canadian equals US$0.738, the rate of exchange on June 30, 2003. This translation should not be construed as a representation that the Canadian dollar amounts shown in the Consolidated Financial Statements could be converted into U.S. dollars at the rate of $1 Canadian equals US$0.738 or at any other rate.

Consolidated Statement of Earnings

Six months ended June 30 *(US$ million, except per share amounts) (unaudited)*	2003
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	$ 5,359
EXPENSES	
Transportation and selling	269
Operating	684
Purchased product	1,847
Administrative	86
Interest, net	125
Foreign exchange (gain)	(395)
Depreciation, depletion and amortization	1,080
	3,696
EARNINGS BEFORE THE UNDERNOTED	1,663
Income tax expense	173
NET EARNINGS FROM CONTINUING OPERATIONS	1,490
NET EARNINGS FROM DISCONTINUED OPERATIONS	216
NET EARNINGS	$ 1,706
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX	(11)
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 1,717
NET EARNINGS PER COMMON SHARE - DILUTED	$ 3.54

Condensed Consolidated Balance Sheet

As at June 30

(US$ million) (unaudited)	2003
ASSETS	
Current Assets	$ 2,512
Capital Assets	17,111
Investments and Other Assets	402
Goodwill	1,822
	$ 21,847
LIABILITIES AND SHAREHOLDERS' EQUITY	
Current Liabilities	$ 1,770
Long-term Debt	4,518
Deferred Credits and Other Liabilities	417
Future Income Taxes	3,809
	10,514
Shareholders' Equity	11,333
	$ 21,847

Condensed Consolidated Statement of Cash Flows

Six months ended June 30

(US$ million, except per share amounts) (unaudited)	2003
CASH FROM OPERATING ACTIVITIES	
Net earnings from continuing operations	$ 1,490
Depreciation, depletion and amortization	1,080
Future income taxes	201
Other	(343)
Cash flow from continuing operations	2,428
Net change in other assets and liabilities	(17)
Net change in non-cash working capital from continuing operations	45
Net change in non-cash working capital from discontinued operations	61
	$ 2,517
CASH USED IN INVESTING ACTIVITIES	$ (1,254)
CASH USED IN FINANCING ACTIVITIES	$ (1,077)
CASH FLOW PER COMON SHARE - DILUTED	$ 5.00

ENCANA CORPORATION

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