February 26, 2004

EnCana earns US$2.4 billion in 2003, cash flow exceeds US$4.4 billion

Annual sales increase by more than 9 percent to 650,200 barrels of oil equivalent per day
Quarterly dividend increased 33 percent to 10 cents US per share

CALGARY, Feb. 26 /CNW/ - EnCana Corporation (TSX & NYSE: ECA) earned US$2.36 billion in 2003, up 183 percent from pro forma 2002. Earnings per common share diluted were $4.92. Earnings from continuing operations, excluding gains due to foreign exchange translation of U.S. dollar debt issued in Canada (after tax) and tax rate changes, increased 97 percent in 2003 from pro forma 2002 to $1.38 billion, or $2.87 per common share diluted. The company's 2003 cash flow increased 67 percent from pro forma 2002 to $4.46 billion, or $9.30 per common share diluted. Strong sales growth and robust commodity prices were significant factors contributing to the strong earnings and cash flow increases. Daily oil, natural gas and natural gas liquids (NGLs) sales volumes were up 9 percent from pro forma 2002, averaging 650,200 barrels of oil equivalent (BOE) per day. Daily sales were comprised of about 2.57 billion cubic feet of natural gas, up 8 percent from pro forma sales in 2002, and approximately 222,500 barrels per day of oil and NGLs, a 13 percent increase. Revenues, net of royalties, in 2003 were $10.2 billion. The EnCana board of directors has approved a 33 percent increase in the company's quarterly dividend to US$0.10 per common share. The previous quarterly dividend was C$0.10 per common share.

2003 financial and operating highlights

	U.S. dollars & protocols	Canadian dollars & protocols
Earnings per share diluted	$4.92, up 184%	$6.83, up 152%
Cash flow per share diluted	$9.30, up 68%	$13.05, up 50%
Natural gas sales	2.57 Bcf/d, up 8%	3.0 Bcf/d, up 9%
Oil and NGLs sales	222,500 bbls/d, up 13%	259,800 bbls/d, up 12%
Total BOE sales	650,200 BOE/d, up 9%	760,700 BOE/d, up 10%

Fourth quarter financial and operating highlights

	U.S. dollars & protocols	Canadian dollars & protocols
Earnings per share diluted	$0.91, up 57%	$1.15, up 25%
Cash flow per share diluted	$2.69, up 39%	$3.55, up 17%
Natural gas sales	2.68 Bcf/d, up 4%	3.1 Bcf/d, up 3%
Oil and NGLs sales	266,900 bbls/d, up 32%	313,800 bbls/d, up 33%
Total BOE sales	713,900 BOE/d, up 13%	833,800 BOE/d, up 12%

IMPORTANT NOTE: EnCana's 2003 year-end financial and operating results are reported in U.S. dollars and follow U.S. protocols, which report sales and reserves on an after-royalties basis, unless otherwise stated. Canadian protocols report sales and reserves on a before-royalties basis. See Note 1 herein. All operating results exclude EnCana's former interest in Syncrude which was sold in 2003 and is treated as a discontinued operation.

All dollar figures are U.S. dollars unless otherwise noted.

All references to 2002 production, sales and financial information 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.

"EnCana delivered outstanding financial and operating results in 2003 and built an even stronger asset base from which to deliver top performance over the long haul. We have increased the intrinsic value of each EnCana share by growing oil and gas sales by an average of 9 percent and increasing proved reserves by 12 percent. The sale of higher cost non-operated assets, combined with the addition of high-quality, long-term growth assets such as Cutbank Ridge, is evidence of our focus on reducing unit costs, growing sales and improving returns," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

"With our 203 percent production replacement coming almost entirely through the drill bit, EnCana added 533 million BOE of proved reserves at a finding, development and acquisition cost of $8.75 per BOE. Our operating and administrative costs of $4.11 per BOE are below our 2003 guidance range and one of the lowest among our large capitalization independent peers," Morgan said.

Solid fourth quarter earnings and cash flow; oil and NGLs sales up 32 percent

In the fourth quarter of 2003, EnCana's earnings increased 51 percent from the same period in 2002 to $426 million, or $0.91 per common share diluted. Earnings from continuing operations, excluding gains due to foreign exchange translation of U.S. dollar debt issued in Canada (after tax) and tax rate changes, increased 32 percent in the fourth quarter of 2003 compared to the same 2002 period to $316 million, or $0.68 per common share diluted. Fourth quarter cash flow increased 34 percent from the fourth quarter of 2002 to $1.25 billion, or $2.69 per common share diluted. Fourth quarter oil, natural gas and NGLs sales averaged 713,900 BOE per day, up 13 percent from 632,700 BOE per day in the same period in 2002. Natural gas sales averaged 2.68 billion cubic feet per day. Gas production was up 9 percent after adjusting for higher levels of withdrawal from storage in the fourth quarter of 2002. Oil and NGLs sales in the fourth quarter of 2003 averaged 266,900 barrels per day, up 32 percent from the same 2002 period. Revenues, net of royalties, were $2.85 billion, up 35 percent from the fourth quarter of 2002. EnCana drilled 1,517 net wells in the fourth quarter of 2003, comprised of 1,306 development wells and 211 exploration wells.

EnCana confirms 10 percent 2004 organic sales growth target

In 2004, EnCana is forecasting daily sales of between 690,000 and 735,000 BOE, comprised of sales between 2.7 billion and 2.85 billion cubic feet of gas per day and 240,000 and 260,000 barrels of oil and NGLs per day. Achieving the middle of these ranges would result in 10 percent sales growth. The company recently increased its oil sales guidance due to strong field performance and the recent acquisition of additional interests in the Scott and Telford oil fields in the U.K. central North Sea. Natural gas sales guidance remains the same and accounts for modest well freeze-offs in January, sales of non-core properties and expected shut-ins due to regulatory rulings in the gas over bitumen issue in northeast Alberta.

"The end of 2003 was marked by an early freeze up that enabled us to advance our drilling programs, taking 2003 drilling to more than 5,600 net wells and giving us a jump on our 2004 program. Natural gas sales exited the year at about 2.7 billion cubic feet per day, near the low end of our 2004 guidance. We have about 1,200 wells, approximately double our normal inventory, drilled across western North America that are awaiting tie in. Most of these wells are in southern Alberta. The tie-in work is planned to occur following spring break-up when additional rigs and crews from northern regions are expected to become available. These well tie-ins, plus substantial field activity elsewhere in North America, are expected to continue to increase gas sales growth as we move through the year," said Randy Eresman, EnCana's Chief Operating Officer.

EnCana's proved reserves grow 12 percent in 2003; production replacement is 203 percent

On February 10, 2004, EnCana announced that proved reserves increased to 2.36 billion BOE, up 12 percent from year-end 2002. This resulted in a 203 percent production replacement, of which essentially all was organically generated through a successful drilling program and positive revisions. The company added 478 million BOE of proved reserves internally, 55 million BOE by acquisition and divested of 51 million BOE for total additions of 482 million BOE before production. By commodity, EnCana added 1.7 trillion cubic feet of natural gas reserves and 204 million barrels of crude oil and NGLs reserves. EnCana's proved reserves at year-end were 8.4 trillion cubic feet of natural gas and 957 million barrels of crude oil and NGLs. The company's proved reserve life index remained at 10 years. All of EnCana's proved reserves are based on reports prepared by independent qualified reserves evaluators using the fundamental geological and engineering data. The process is supervised by a committee of independent directors. EnCana believes this is the most stringent standard of reserves governance available to the industry, and that it goes well beyond external reviews or audits of reserves.

"Our reserve additions, two barrels of oil equivalent for every barrel produced, clearly demonstrate the continuous, reliable drill bit growth available through relatively low risk, repeatable development drilling on our huge resource play dominated asset base. We added 1.7 trillion cubic feet of North American gas at a time when overall industry gas reserves and production growth is faltering. We have clearly identifiable captured resource potential on our existing land base which should allow similar organic reserves and production growth for years to come," Morgan said.

Finding, development and acquisition capital

EnCana invested about $4,650 million of finding, development and acquisition capital, which added 533 million BOE of proved reserves. This resulted in a finding, development and acquisition cost of $8.75 per BOE. During 2003, the average exchange rate was $0.716 to one Canadian dollar, which is a 12 percent increase from the average 2002 rate of $0.637 to one Canadian dollar. As a result of the conversion from Canadian to U.S. dollars, approximately $350 million was added to EnCana's U.S. dollar finding, development and acquisition capital compared to the previous year. Excluding this estimated appreciation in the Canadian dollar, EnCana's 2003 finding, development and acquisition costs would be lower by about $0.65 per BOE and result in a marginal increase from the 2002 cost of about $7.95 per BOE.

North American natural gas prices rise in 2003

Natural gas prices across North America rebounded over weaker 2002 prices. The average benchmark NYMEX index price in 2003 was $5.39 per thousand cubic feet, up 67 percent from the average price in 2002, driven by lower levels of natural gas in storage and continued concerns about North American supply. EnCana's average realized natural gas price, excluding hedging, was $4.87 per thousand cubic feet; including hedging it was $4.77 per thousand cubic feet. This represents an increase of 66 percent over the average pro forma 2002 price including hedging. In the fourth quarter the average benchmark NYMEX index price was $4.58 per thousand cubic feet, an increase of 15 percent from the fourth quarter of 2002. The company's fourth quarter average realized natural gas price, including hedging, was $4.65 per thousand cubic feet, up 29 percent compared to the fourth quarter of 2002.

World oil prices strong in 2003; Canadian heavy oil price differentials widen

World oil prices improved during 2003 as strong Asian demand, supply disruptions in Venezuela and Nigeria, the slow return of Iraqi oil production and OPEC's production management, kept crude oil inventories low. During the year, the average benchmark West Texas Intermediate (WTI) crude oil price was $30.99 per barrel, up 19 percent over 2002. Canadian and Ecuadorian heavy oil price differentials widened during the year primarily in response to the higher WTI price. In September 2003, the OCP Pipeline began operations and the shippers created a new Ecuadorian crude oil stream called NAPO blend. The NAPO blend is a heavier crude oil than the Oriente blend. It received a WTI differential that averaged $8.06 per barrel in 2003, compared to the average Oriente differential of $5.59 per barrel. In 2003, EnCana's average realized oil and NGLs price, excluding hedging, was $23.25 per barrel; including hedging it was $20.71 per barrel. In the fourth quarter, the company's average realized oil and NGLs price, excluding hedging, was $22.51 per barrel; including hedging it was $20.36 per barrel.

Risk management programs help reduce cash flow risk

EnCana's risk management program is designed to partially mitigate the volatility associated with commodity prices, exchange rates and interest rates. From time to time, EnCana will fix prices on future oil and gas sales to reduce the market risk associated with forecasted cash flows. EnCana has about 45 percent of projected 2004 gas sales, after royalties, hedged at an average effective NYMEX price of about $5.24 per thousand cubic feet, based upon an exchange rate of $0.758 to one Canadian dollar and a $0.73 per thousand cubic feet AECO basis for Canadian conversions. About half of EnCana's projected 2004 oil sales are hedged with swaps or subject to costless collars between $20 and $26 WTI. The detailed risk management positions at December 31, 2003 are presented in Note 12 to the unaudited fourth quarter Consolidated Financial Statements. EnCana's financial commodity price and currency risk management measures resulted in revenue being lower in the fourth quarter by approximately $15 million, comprised of $53 million of lower revenue on oil sales and $38 million of higher revenue on gas sales. For the full year, EnCana's financial commodity and currency risk management measures resulted in revenue being lower by approximately $297 million, comprised of $206 million on oil sales and $91 million on gas sales.

Consolidated EnCana Highlights

US$ and U.S. protocols

Financial Highlights (as at and for the period ended December 31) (US$ millions, except per share amounts)	Q4 2003	Q4 2002	% Change	2003	Pro forma(3) 2002	% Change
Revenues, net of royalties	2,850	2,116	+ 35	10,216	6,967	+ 47
Cash flow	1,254	935	+ 34	4,459	2,664	+ 67
Per share - basic	2.71	1.96	+ 38	9.41	5.62	+ 67
Per share - diluted	2.69	1.94	+ 39	9.30	5.54	+ 68
Net earnings	426	282	+ 51	2,360	833	+ 183
Per share - basic(1)	0.92	0.59	+ 56	4.98	1.76	+ 183
Per share - diluted	0.91	0.58	+ 57	4.92	1.73	+ 184
Earnings from continuing operations, excluding foreign						

exchange translation of U.S. dollar debt issued in Canada (after tax) and tax rate change gain	316	239	+ 32	1,375	697	+ 97
Per share - diluted	0.68	0.49	+ 39	2.87	1.45	+ 98
Net capital investment	1,381	778	+ 78	3,422	3,234	+ 6
Total assets				24,110	19,912	+ 21
Long-term debt				6,088	5,051	+ 21
Shareholders' equity				11,278	8,718	+ 29
Debt-to-capitalization ratio (adjusted for working capital)				34%	31%	

Common shares (millions)						
Outstanding at December 31	460.6	478.9	- 3.8	460.6	478.9	- 3.8
Weighted average (diluted)	465.9	482.6	- 3.5	479.7	481.1	- 0.3

Operating Highlights (for the period ended Dec. 31)	Q4 2003	Q4 2002	% Change	2003	Pro forma(3) 2002	% Change
(After royalties)						
Natural Gas (MMcf/d)						
Production	2,682	2,467	+ 9	2,536	2,358	+ 8
Withdrawal (Injection)	-	117		30	22	
Total natural gas sales (MMcf/d)	2,682	2,584	+ 4	2,566	2,380	+ 8
Oil and NGLs sales (bbls/d)						
North America	174,471	158,358	+ 10	165,895	150,484	+ 10
International	92,419	43,686	+ 112	56,649	47,119	+ 20
Total liquids sales (bbls/d)	266,890	202,044	+ 32	222,544	197,603	+ 13
Total sales (BOE/d)(2)	713,890	632,711	+ 13	650,211	594,270	+ 9

(1) Impact of including share options in earnings calculations
The company has early adopted the Canadian accounting standard for stock-based compensation as outlined in the Canadian Institute of Chartered Accountants Handbook section 3870. Following this standard, the policy has been adopted prospectively, meaning prior years have not been restated. As a result, EnCana recorded compensation expense of $18 million in relation to outstanding share options issued in 2003. 2003 net earnings per common share - basic would have been $5.02 per common share, $0.04 per common share higher, had the company not adopted this standard.

(2) Excludes EnCana's share of Syncrude volumes, which were nil in the fourth quarter of 2003, compared to 33,918 barrels per day in the fourth quarter of 2002. For the year ended 2003, Syncrude volumes averaged 7,629 barrels per day, compared to 31,267 barrels per day in 2002.

(3) Important Notice: Readers are cautioned that comparisons to 2002 full year results are based on 2002 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.

Natural gas, oil and NGLs prices US$ and U.S. protocols

2003 Prices	Q4 2003	Q4 2002	% Change	2003	Pro forma(3) 2002	% Change
Natural Gas (US$/Mcf)						
Including hedging						
Canada	4.66	3.54	+ 32	4.74	2.83	+ 67
U.S.	4.58	3.82	+ 20	4.90	3.12	+ 57
Excluding hedging						
Canada	4.41	3.60	+ 23	4.87	2.78	+ 75
U.S.	4.71	3.48	+ 35	4.88	2.86	+ 71
Total North American gas (US$/Mcf)						
Including hedging	4.65	3.60	+ 29	4.77	2.88	+ 66
Excluding hedging	4.49	3.58	+ 25	4.87	2.80	+ 74
Oil and NGLs (US$/bbl)						
Including hedging						
North American oil						
Light/medium	21.79	23.48	- 7	22.54	21.47	+ 5
Heavy	14.62	16.54	- 12	15.70	16.85	- 7
International oil						
Ecuador	23.57	24.02	- 2	24.21	21.24	+ 14
U.K.	27.05	25.73	+ 5	28.11	24.70	+ 14
Natural gas liquids	25.77	23.06	+ 12	25.33	19.42	+ 30
Excluding hedging						
North American oil						
Light/medium	25.53	24.39	+ 5	26.61	22.28	+ 19
Heavy	18.43	17.38	+ 6	19.61	17.35	+ 13
International oil						
Ecuador	23.57	24.02	- 2	24.21	21.24	+ 14
U.K.	27.05	25.73	+ 5	28.11	24.76	+ 14
Natural gas liquids	25.77	23.06	+ 12	25.33	19.42	+ 30
Total oil and NGLs (US$/bbl)						
Including hedging	20.36	20.94	- 3	20.71	19.71	+ 5
Excluding hedging	22.51	21.51	+ 5	23.25	20.13	+ 15

Canadian protocol reporting

During the transition period over year-end 2003, when EnCana changed from reporting in Canadian dollars and before-royalty reserves and production protocols to U.S. dollars and after-royalty reserves and production protocols, EnCana is providing its sales highlights table in both formats. EnCana's 2003 annual report will be entirely in U.S. dollars and protocols.

Consolidated EnCana Highlights

Canadian $ and Canadian protocols

Financial Highlights (as at and for the period ended December 31) (C$ millions, except per share amounts)	Q4 2003	Q4 2002	% Change	2003	Pro forma(3) 2002	% Change
Revenues, net of royalties and production and mineral taxes	3,674	3,258	+ 13	14,052	10,747	+ 31
Cash flow						
Per share - basic	1,652	1,464	+ 13	6,262	4,187	+ 50
Per share - diluted	3.57	3.06	+ 17	13.21	8.84	+ 49
	3.55	3.03	+ 17	13.05	8.70	+ 50
Net earnings						
Per share - basic(4)	534	443	+ 21	3,274	1,305	+ 151
Per share - diluted	1.16	0.93	+ 25	6.91	2.75	+ 151
	1.15	0.92	+ 25	6.83	2.71	+ 152
Earnings from continuing operations, excluding foreign exchange translation of U.S. dollar debt issued in Canada (after tax) and tax rate change gain	410	372	+ 10	1,934	1,086	+ 78
Per share - diluted	0.89	0.77	+ 16	4.03	2.26	+ 78
Net capital investment	1,827	1,223	+ 49	4,615	5,074	- 9
Total assets				31,157	31,452	- 1
Long-term debt				7,866	7,978	- 1
Shareholders' equity				14,575	13,771	+ 6
Debt-to-capitalization ratio (adjusted for working capital)				34%	31%	

Operating Highlights (for the period ended Dec. 31)	Q4 2003	Q4 2002	% Change	2003	Pro forma(3) 2002	% Change
(Before royalties)						
Natural Gas (MMcf/d)						
Production	3,120	2,888	+ 8	2,970	2,730	+ 9
Withdrawal						

(Injection)	-	149		35	28	
Total natural gas sales (MMcf/d)	3,120	3,037	+ 3	3,005	2,758	+ 9
Oil and NGLs sales (bbls/d)						
North America	195,129	179,067	+ 9	187,196	169,722	+ 10
International	118,705	57,720	+ 106	72,651	61,609	+ 18
Total liquids sales (bbls/d)	313,834	236,787	+ 33	259,847	231,331	+ 12
Total sales (BOE/d)(5)	833,834	742,954	+ 12	760,680	690,998	+ 10

(4) Impact of including share options in earnings calculations
The company has early adopted the Canadian accounting standard for stock-based compensation as outlined in the Canadian Institute of Chartered Accountants Handbook section 3870. Following this standard, the policy has been adopted prospectively, meaning prior years have not been restated. As a result, EnCana recorded compensation expense of C$24 million in relation to outstanding share options issued in 2003. 2003 net earnings per common share - basic would have been C$6.96 per common share, C$0.05 per common share higher, had the company not adopted this standard.
(5) Excludes EnCana's share of Syncrude volumes, which were nil in the fourth quarter of 2003, compared to 34,261 barrels per day in the fourth quarter of 2002. For the year ended 2003, Syncrude volumes averaged 7,697 barrels per day, compared to 31,556 barrels per day in 2002.

Natural gas, oil and NGLs prices Canadian $ and Canadian protocols

2003 Prices	Q4 2003	Q4 2002	% Change	2003	Pro forma(3) 2002	% Change
Natural Gas (C$/Mcf)						
Including hedging						
Canada	5.54	5.09	+ 9	6.16	4.05	+ 52
U.S.	5.41	5.16	+ 5	6.32	4.12	+ 53
Excluding hedging						
Canada	5.25	5.17	+ 2	6.34	3.98	+ 59
U.S.	5.54	4.74	+ 17	6.28	3.79	+ 66
Total North American gas (C$/Mcf)						
Including hedging	5.51	5.11	+ 8	6.19	4.07	+ 52
Excluding hedging	5.33	5.08	+ 5	6.32	3.96	+ 60
Oil and NGLs (C$/bbl)						
Including hedging						
North American oil						
Light/medium	27.37	35.10	- 22	30.12	32.40	- 7
Heavy	17.69	24.63	- 28	20.79	25.34	- 18
International oil						
Ecuador	28.16	35.38	- 20	31.13	31.30	- 1
U.K.	33.36	37.99	- 12	36.50	36.14	+ 1

Natural gas liquids	33.83	36.15	- 6	35.49	30.44	+ 17
Excluding hedging						
North American oil						
Light/medium	31.84	36.36	- 12	35.33	33.53	+ 5
Heavy	22.21	25.81	- 14	25.74	26.04	- 1
International oil						
Ecuador	28.16	35.38	- 20	31.13	31.30	- 1
U.K.	33.36	37.99	- 12	36.50	36.23	+ 1
Natural gas liquids	33.83	36.15	- 6	35.49	30.44	+ 17
Total oil and NGLs (C$/bbl)						
Including hedging	25.20	31.57	- 20	27.65	29.70	- 7
Excluding hedging	27.60	32.33	- 15	30.73	30.26	+ 2

Corporate developments

Quarterly dividend increased 33 percent to US$0.10 per share

EnCana's board of directors has declared a quarterly dividend of $0.10 per share payable on March 31, 2004 to common shareholders of record as of March 15, 2004. This is a 33 percent increase in the dividend based on current exchange rates. The previous quarterly dividend was C$0.10 per common share.

Normal Course Issuer Bid purchases

In October 2003, EnCana received approval from the Toronto Stock Exchange to purchase, for cancellation, common shares under a Normal Course Issuer Bid. Under the bid, EnCana is entitled to purchase for cancellation up to 23.2 million of its common shares over a 12-month period ending October 21, 2004. In 2003, combined purchases under the current bid and a previous bid were 23.8 million shares at an average price of C$49.65 per share. These purchases more than offset the approximately 5.5 million shares issued in 2003 as a result of the exercise of share purchase options. In 2004, EnCana has purchased for cancellation 2.5 million of its shares at an average price of C$54.52 per share under its current Normal Course Issuer Bid, approximately equal to share option exercises.

Coupon Reset Subordinated Term Securities to be redeemed

On February 4, 2004, the company announced that it intends to redeem on March 23, 2004 all of its Coupon Reset Subordinated Term Securities, Series A (Term Securities), which have an aggregate principal amount of C$125,625,000. The redemption price of the Term Securities is the principal amount thereof plus accrued and unpaid interest to the redemption date.

Financial strength

EnCana maintained its strong balance sheet in 2003. At December 31, 2003, the company's net debt-to-capitalization ratio was 34:66. EnCana's net debt-to-EBITDA multiple, on a trailing 12-month basis, was 1.3 times.

On October 2, 2003, EnCana completed a public offering in the United States of $500 million of 4.75% Notes due October 15, 2013. The net proceeds of the offering have been used to repay existing floating-rate bank and commercial paper indebtedness. As at December 31, 2003, approximately 52 percent of EnCana's outstanding debt was in U.S. dollars and 65 percent of total debt was long-term fixed rate. EnCana maintains strong investment grade credit ratings from three rating services: A(low) by Dominion Bond Rating Service Limited; Baa1 by Moody's Investors Service and A- by Standard and Poor's Ratings Services. At December 31, 2003, the company also had a $3.1 billion credit facility with a syndicate of major banks and lending institutions, of which more than $1.3 billion was unutilized.

EnCana generated 2003 cash flow of $4,459 million; of that amount approximately $1,900 million was reinvested to maintain production at previous levels, resulting in free cash flow of $2,559 million available for dividends, share purchases and reinvestment in growth opportunities. Core capital investment was $4,502 million, $1,319 million of which was invested in the fourth quarter. Asset and corporate acquisitions in the year were $820 million and proceeds from asset and corporate dispositions were $2,285 million, including the assumption of $385 million of debt by a purchaser, resulting in net capital investment of $3,037 million.

EnCana 2003 capital investment

	(US$ million)
Upstream	
Offset production declines	1,900
2003 and part of 2004 growth	1,500
Exploration and long-term development	552
Cutbank Ridge land purchase	270
Upstream total	4,222
Midstream, marketing and corporate	280
Core capital total	4,502
Other	
Leased equipment purchases	262
Minor corporate acquisitions	207
Upstream asset acquisitions	351
Other total	820
Divestitures	
Express and Cold Lake pipelines(*)	(1,024)
Syncrude	(946)
Upstream minor properties	(301)
Minor corporate divestitures	(14)
Divestitures total	(2,285)
Net capital investment	3,037

(*) Net proceeds were $1,024 million less $385 million of debt, which was assumed by the purchaser, resulting in net cash proceeds of $639 million.

Cash taxes

During the fourth quarter of 2003, EnCana recognized a current income tax recovery of $73 million resulting in a cumulative income tax recovery of $56 million for the year. The fourth quarter recovery relates principally to a shift of approximately $90 million of previously anticipated 2003 current Canadian income tax expense to 2004.

Operational highlights

Upstream

Strong sales growth, international achievements and strategic refinement in 2003

EnCana's 2003 upstream operations were marked by continued strong growth in daily sales and year-over-year proved reserves additions, plus some significant strategic developments. Sale of the company's interest in Syncrude, plus the recent divestiture of its interest in Petrovera Resources, narrowed the company's Canadian oil focus towards developing its low-cost, 100 percent owned and operated heavy oil reserves, primarily through steam-assisted gravity drainage (SAGD) projects at Foster Creek and Christina Lake, its Pelican Lake water flood project, all in northeast Alberta and its heavy oil property at Suffield in southern Alberta. In the fourth quarter SAGD production reached more than 35,000 barrels per day following the completion of the successful expansion of the Foster Creek project. Pelican Lake production averaged 16,000 barrels of oil per day in 2003 as a result of a successful water flood and Suffield production averaged 27,000 barrels per day in 2003, an 18 percent increase from 2002 levels. EnCana's other major oil development this year was the completion and opening of the OCP Pipeline in Ecuador, a five-year project that enabled EnCana to double its production to more than 70,000 barrels of oil per day in the fourth quarter. In the U.K. central North Sea, the acquisition of interests in the Scott and Telford fields from Amerada Hess and Shell has brought current production to about 21,000 BOE per day. Development of the Buzzard oil field is progressing as planned following the receipt of regulatory approval. First oil from Buzzard is expected in late 2006.

In natural gas, EnCana achieved strong growth from its prolific resource plays in the U.S. Rockies, acquired a new, high potential resource play at Cutbank Ridge in British Columbia and extended shallow gas development in southern Alberta to include commercial production from coalbed methane (CBM). In 2003, the company drilled 5,632 net wells, about 13 percent more than forecast, which included 5,016 development wells and 616 exploration wells. EnCana currently has about 25 rigs running in the U.S. Rockies and about 100 rigs across Western Canada.

North America

U.S.A. region grows 2003 natural gas production by 49 percent

U.S.A. production averaged 588 million cubic feet in 2003, up 49 percent from pro forma 2002. Fourth quarter production averaged 654 million cubic feet per day, up 27 percent from the same period in 2002. Current U.S.A. production is averaging 675 million cubic feet per day. In order to help mitigate pricing risk due to gas transportation constraints out of the U.S. Rockies, EnCana has fixed the price differential between NYMEX and the Rockies on an average of 645 million cubic feet per day of forecast gas sales for 2004 through 2007 at an average basis of $0.52 per thousand cubic feet.

"We've made strong progress during 2003 developing our two core properties, Jonah in Wyoming and Mamm Creek in Colorado, where production has increased approximately 50 percent in the past year. In 2004, we look forward to the completion of the regulatory review of our infill drilling plans at Jonah, plus advancing the development of promising new resource plays in Colorado and Texas," said Roger Biemans, President of EnCana's U.S.A. region.

Continued drilling success at Greater Sierra

EnCana ramped up production at the Greater Sierra resource play in 2003 by drilling 207 net wells in the area. Greater Sierra production exited 2003 at about 215 million cubic feet per day. Favourable changes in the B.C. government's royalty regime for summer drilling and the province's commitment to improve road infrastructure, combined with early winter drilling conditions in the fourth quarter, enabled EnCana to step up its development at Greater Sierra. Construction of EnCana's new Ekwan Pipeline started in December. This 80 kilometre link to the Alberta gas transmission system has a planned capacity of more than 400 million cubic feet per day. With start-up planned during the second quarter of 2004, the Ekwan Pipeline is expected to facilitate continued sales growth from northeast B.C., where the company currently has about 32 rigs drilling this winter.

EnCana plans to drill 300 coalbed methane wells in 2004

In 2003, the company drilled about 270 CBM wells; about half are on production. CBM production exited the year at about 10 million cubic feet per day. EnCana is expanding CBM development on its 700,000 acres of 100 percent owned royalty-free lands in southern Alberta. EnCana expects to drill approximately 300 wells in 2004, taking production to about 30 million cubic feet per day by year-end 2004. Over the next five years, EnCana expects to increase natural gas production from coal seams to more than 200 million cubic feet per day.

Cold January weather and regulatory ruling trim gas production

Extremely cold weather across Western Canada in January 2004 caused some

EnCana gas wells to freeze, resulting in the shut in, on average, of about 100 million cubic feet of daily gas production during January. In addition, the Alberta Energy and Utilities Board recently ordered some additional shut-ins of certain gas wells located in areas of northeast Alberta where bitumen is also produced from deeper geological formations. In September 2003, the regulator shut in about 10 million cubic feet of EnCana's daily gas production. The most recent ruling could take that total to about 20 million cubic feet per day. The shut-in rulings are subject to additional AEUB hearings in the weeks ahead that will determine their finality. Also, about 15 million cubic feet per day of non-core Canadian gas production has been sold so far in 2004. These gas production reductions have been accounted for in the company's 2004 sales forecast range.

Sharpening heavy oil focus - sale of 53.3 percent interest in Petrovera

On February 18, 2004, EnCana sold its 53.3 percent interest in Petrovera Resources for approximately $285 million, before working capital adjustments. In 2003, EnCana's share of Petrovera's production represented about 20,000 BOE per day. This divestiture is consistent with EnCana's strategy to have high working interest, operated assets where it is able to apply core competencies and manage operating costs.

New plan being developed for Deep Panuke

EnCana has initiated work on a new plan for a potential offshore development at Deep Panuke. Two successful exploration wells near the Deep Panuke natural gas field - Margaree and Marcoh, have increased the company's confidence in the commercial potential of this discovery located about 250 kilometres southeast of Halifax, Nova Scotia. Given the numerous changes at Deep Panuke, the original development plan was no longer appropriate. Consequently, on December 3, 2003, EnCana withdrew the original Deep Panuke development applications filed with the National Energy Board and the Canada-Nova Scotia Offshore Petroleum Board in March 2002.

International

International sales up 113 percent in the fourth quarter

Sales from EnCana's international operations averaged 95,800 BOE per day in the fourth quarter, up 113 percent from sales of about 45,000 BOE per day in the same period last year. This doubling of sales results from the opening of the OCP Pipeline in Ecuador in early September 2003 and increased ownership in the Scott and Telford fields in the U.K. central North Sea.

Ecuador production reaches full stride

EnCana has completed its first full quarter of unrestrained production from its Ecuador oil fields, selling 77,400 barrels of oil per day in the fourth quarter of 2003, up 115 percent from the same period in 2002. For the full year, Ecuador sales reached about 46,500 barrels per day, up 27 percent compared to pro forma 2002 sales. The majority of EnCana's Ecuador production growth in 2003 was from EnCana's 100 percent owned Tarapoa block and the company's 40 percent non-operated interest in Block 15. In 2004, EnCana is focused on achieving operating cost efficiencies in all Ecuador operations and examining additional exploration opportunities on its expanded base of more than 800,000 acres of net undeveloped land.

Buzzard field development plan receives approval

On November 27, 2003, the U.K. Department of Trade and Industry granted regulatory approval of EnCana's development plan for the North Sea's Buzzard oil field. Production from the field is expected to start in late 2006, reaching a plateau of about 180,000 barrels of oil per day in 2007. The $2 billion Buzzard development will consist of three bridge-linked steel platforms supporting facilities for drilling, production, and utilities and accommodation respectively. The facilities include two subsea water injection manifolds located about two kilometres from the platform. The crude oil is expected to be transported to the mainland via a pipeline tie-in to the nearby Forties Pipeline System. The natural gas is expected to flow to market via the Frigg Pipeline System. Buzzard is located in about 100 metres of water, approximately 100 kilometres northeast of Aberdeen, Scotland and about 55 kilometres from the coast at Peterhead. EnCana is the operator of Buzzard, holding approximately 43 percent of the field, which is expected to produce about 75,000 barrels per day of light, royalty-free oil net to EnCana once the field reaches plateau level.

EnCana increased interests in Scott & Telford fields and takes over operatorship

EnCana has more than doubled its ownership of the Scott and Telford oilfields in the U.K. central North Sea. In October 2003, EnCana acquired an additional 14 percent interest in the Scott and Telford fields and subsequently took over operatorship. U.K. sales averaged 18,400 BOE per day in the fourth quarter, an increase of 102 percent over the fourth quarter of 2002. In early 2004, EnCana closed a second transaction, increasing its interests to 41 percent of Scott and 54.3 percent of Telford. EnCana is focusing its efforts on reducing the per-unit operating costs at Scott-Telford and accumulating substantial operating experience that it intends to apply in the development and daily operations of the Buzzard project.

Midstream & Marketing

EnCana's Midstream & Marketing division achieved $53 million of operating cash flow in 2003, which was within the company's 2003 revised guidance range of $48 million to $55 million. Lower than expected seasonal price differentials during much of the year resulted in lower prices bid for storage capacity and reduced opportunities for storage optimization as compared to previous years.

Expansion of independent gas storage in Alberta and California

In 2003, EnCana completed construction of its Countess gas storage facility and injected 11 billion cubic feet of gas over the year. Future expansion plans at Countess are expected to take capacity to 30 billion cubic feet in the summer of 2004 and 40 billion cubic feet in 2005, when maximum withdrawal capability is expected to reach 1.2 billion cubic feet per day. Completion of a 10 billion cubic feet expansion of the Wild Goose facility in northern California is expected in April 2004, bringing the total working gas capacity to 24 billion cubic feet. The expansion is expected to more than double the facility's withdrawal capability to 480 million cubic feet per day and expand daily injection capability from 80 million to 450 million cubic feet per day. With the company's recently expanded storage network, plus other projects underway or in planning, EnCana expects to fortify its position as a North American leader in independent gas storage.

Expansion of U.S. Rockies gas transmission capacity planned

Entrega Gas Pipeline Inc., an affiliate of EnCana Oil & Gas (USA) Inc., plans to file a letter with the U.S. Federal Energy Regulatory Commission outlining preliminary plans to build a natural gas pipeline from northwest Colorado to the Cheyenne gas trading hub in northeast Colorado. Entrega is developing this proposed pipeline based on the industry's growth forecast for gas production and the need to expand gas transportation capacity from the U.S. Rockies to major American markets. The Entrega Pipeline, with an expected initial capacity of 1.3 billion cubic feet per day, is planned to begin service in 2005. The project is subject to approval by the EnCana board of directors and regulatory approval by federal and state agencies. The company plans to hold an open season seeking shippers to contract for capacity on the proposed Entrega Pipeline.

FINANCIAL INFORMATION

NOTE: All financial information in this news release reflects actual results, except for the company's 2002 pro forma twelve-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 twelve 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 news release and EnCana's supplemental information, including supplemental Canadian dollar and protocol information, are posted on the company's Web site: www.encana.com.

Updated guidance

EnCana has posted an updated guidance document on its Web site.

CONFERENCE CALL TODAY

EnCana Corporation will host a conference call today, Thursday, February 26, 2004 starting at 9 a.m., Mountain Time (11 a.m. Eastern Time), to discuss EnCana's fourth quarter and year-end 2003 financial and operating results.

To participate, please dial (719) 457-2641 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 5 p.m. on February 26, 2004 until midnight March 2, 2004 by dialing (888) 203-1112 or (719) 457-0820 and entering pass code 759990.

A live audio Web cast of the conference call will also be available via EnCana's Web site, www.encana.com, under Investor Relations. The Web cast will be archived for approximately 90 days.

NOTE 1: EnCana financial results in U.S. dollars and operating results according to U.S. protocols

Starting with year-end 2003, EnCana is reporting its financial results in U.S. dollars and its reserves and production according to U.S. protocols in order to facilitate a more direct comparison to other North American upstream oil and natural gas exploration and development companies. Reserves and production are reported on an after-royalties basis. There is no change to the physical volumes produced and sold or to the actual reserves as a result of adopting U.S. protocols. However, readers should note that the change results in a general lowering of reported numbers for EnCana's sales volumes and impacts the percentage changes year over year. For example, under previous Canadian protocols, if EnCana produced and sold 100 barrels of oil at the wellhead, it reported sales of 100 barrels. Under the new U.S. protocol, royalties paid to the Crown, state or mineral rights owners are deducted before sales volumes are reported. For example, under U.S. protocols, if EnCana produced and sold 100 barrels and the oil was subject to a 20 percent royalty, EnCana would report sales of 80 barrels of oil.

NOTE 2: Non-GAAP measures

This press release contains references to cash flow, free cash flow, EBITDA (earnings before interest, income taxes, depreciation, depletion and amortization) and earnings from continuing operations, excluding gains from foreign exchange translation of U.S. dollar denominated debt issued in Canada (after tax) and tax rate changes, and the related basic and diluted per common share amounts as applicable, which are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this press release in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

EnCana Corporation

With an enterprise value of approximately $25 billion, EnCana is one of the world's leading independent oil and gas companies and North America's largest independent natural gas producer and gas storage operator. Ninety percent of the company's assets are 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. International subsidiaries operate two key high potential international growth platforms: Ecuador, where it is the largest private sector oil producer, and the U.K. central North Sea, where it is the operator of a large oil discovery. EnCana and its subsidiaries also conduct high upside potential new ventures exploration in other parts of the world. EnCana is driven to be the industry's high performance benchmark in production cost, per-share growth and value creation for shareholders. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

ADVISORY REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION - The reserves and other oil and gas information contained in this news release has been prepared in accordance with U.S. disclosure standards, in reliance on an exemption from the Canadian disclosure standards granted to EnCana by Canadian securities regulatory authorities. Such information may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). The reserves quantities disclosed in this news release represent net proved reserves calculated on a constant price basis using the standards contained in U.S. Securities and Exchange Commission Regulation S-X and FAS 69.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101) differences in the estimated proved reserve quantities based on constant prices should not be material. EnCana concurs with this assessment.

The finding, development and acquisition costs per BOE in this press release have been calculated by dividing total capital expended on finding, development and acquisition activities by additions to proved reserves, before divestitures, which are the sum of revisions, extensions & discoveries and acquisitions. This calculation is commonly used in the U.S. EnCana's average finding, development and acquisition cost per BOE for its three most recent financial years was $8.35 (combining the results of PanCanadian and AEC for periods prior to the merger).

In this news release, certain natural gas volumes have been converted to BOE on the basis of six thousand cubic feet (Mcf) to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6Mcf:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS - In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this news release are forward-looking statements within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements in this news release include, but are not limited to: future economic performance (including per share growth); anticipated life of proved reserves; anticipated success of resource plays; potential success of such projects as SAGD, Ecuador, Deep Panuke, Buzzard, Cutbank Ridge, Wild Goose, Countess and Entrega; anticipated capacities of the Wild Goose and Countess storage facilities; anticipated completion dates for the expansions at Wild Goose and Countess; the anticipated completion, timing and capacity of the Entrega Pipeline; the anticipated production of oil from Buzzard in 2006 and 2007; anticipated leadership in North America for independent gas storage; estimated recycle ratios; potential demand for gas; anticipated production in 2004 and beyond; anticipated development of undeveloped reserves over the next three years; anticipated drilling; potential capital expenditures and investment; anticipated completion and capacity of the Ekwan Pipeline; anticipated CBM development in 2004 and beyond; potential oil and gas sales in 2004 and beyond, anticipated costs; potential risks associated with drilling and references to potential exploration. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved 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 war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; 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 news release are made as of the date of this news release, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

Interim Consolidated Financial Statements
(unaudited)
For the period ended December 31, 2003
EnCana Corporation
U.S. DOLLARS

Prepared in US$

Interim Report
For the period ended December 31, 2003
EnCana Corporation
CONSOLIDATED STATEMENT OF EARNINGS

(unaudited) (US$ millions, except per share amounts)	December 31			
	Three Months Ended		Year Ended	
	2003	2002	2003	2002

			(restated - Note 2)		(restated - Note 2)
REVENUES, NET OF ROYALTIES	(Note 4)	$ 2,850	$ 2,116	$ 10,216	$ 6,276
EXPENSES	(Note 4)				
Production and mineral taxes		58	41	189	119
Transportation and selling		170	121	545	364
Operating		337	258	1,297	813
Purchased product		1,049	720	3,455	2,200
Depreciation, depletion and amortization		725	452	2,222	1,304
Administrative		52	48	173	119
Interest, net		85	119	287	290
Accretion of asset retirement obligation	(Note 9)	4	4	19	13
Foreign exchange (gain) loss	(Note 6)	(165)	3	(601)	(14)
Stock-based compensation	(Note 2)	6	-	18	-
Gain on corporate disposition		-	(33)	-	(33)
		2,321	1,733	7,604	5,175
NET EARNINGS BEFORE INCOME TAX		529	383	2,612	1,101
Income tax expense	(Note 7)	103	135	445	366
NET EARNINGS FROM CONTINUING OPERATIONS		426	248	2,167	735
NET EARNINGS FROM DISCONTINUED OPERATIONS	(Note 5)	-	34	193	77
NET EARNINGS		$ 426	$ 282	$ 2,360	$ 812
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	(Note 11)				
Basic		$ 0.92	$ 0.52	$ 4.57	$ 1.76
Diluted		$ 0.91	$ 0.51	$ 4.52	$ 1.74
NET EARNINGS PER COMMON SHARE	(Note 11)				
Basic		$ 0.92	$ 0.59	$ 4.98	$ 1.94
Diluted		$ 0.91	$ 0.58	$ 4.92	$ 1.92

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

	Year Ended December 31	
(unaudited) (US$ millions)	2003	2002

			(restated - Note 2)
RETAINED EARNINGS, BEGINNING OF YEAR			
As previously reported		$ 3,457	$ 2,787
Retroactive adjustment for changes in accounting policies	(Note 2)	66	32
As restated		3,523	2,819
Net Earnings		2,360	812
Dividends on Common Shares		(139)	(108)
Charges for Normal Course Issuer Bid	(Note 10)	(468)	-
RETAINED EARNINGS, END OF YEAR		$ 5,276	$ 3,523

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED BALANCE SHEET

(unaudited) (US$ millions)		As at December 31, 2003	As at December 31, 2002
			(restated - Note 2)
ASSETS			
Current Assets			
Cash and cash equivalents		$ 148	$ 116
Accounts receivable and accrued revenues		1,367	1,258
Inventories		573	281
Assets of discontinued operations	(Note 5)	-	2,155
		2,088	3,810
Property, Plant and Equipment, net	(Note 4)	19,545	14,247
Investments and Other Assets		566	292
Goodwill		1,911	1,563
	(Note 4)	$ 24,110	$ 19,912
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 1,579	$ 1,445
Income tax payable		65	13
Current portion of long-term debt	(Note 8)	287	134
Liabilities of discontinued operations	(Note 5)	-	1,100
		1,931	2,692
Long-Term Debt	(Note 8)	6,088	5,051
Other Liabilities		21	54
Asset Retirement Obligation	(Note 9)	430	309
Future Income Taxes		4,362	3,088
		12,832	11,194
Shareholders' Equity			
Share capital	(Note 10)	5,305	5,511
Share options, net		55	84
Paid in surplus		18	51
Retained earnings		5,276	3,523
Foreign currency translation adjustment		624	(451)

	11,278	8,718
	$ 24,110	$ 19,912

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

		December 31			
		Three Months Ended		Year Ended	
(unaudited) (US$ millions)		2003	2002	2003	2002
			(restated - Note 2)		(restated - Note 2)
OPERATING ACTIVITIES					
Net earnings from continuing operations		$ 426	$ 248	$ 2,167	$ 735
Depreciation, depletion and amortization		725	452	2,222	1,304
Future income taxes	(Note 7)	176	242	501	404
Unrealized foreign exchange (gain)		(141)	(8)	(545)	(23)
Accretion of asset retirement obligation		4	4	19	13
Other		27	(64)	56	(166)
Cash flow from continuing operations		1,217	874	4,420	2,267
Cash flow from discontinued operations		37	61	39	152
Cash flow		1,254	935	4,459	2,419
Net change in other assets and liabilities		(2)	(1)	(84)	(17)
Net change in non-cash working capital from continuing operations		(301)	(346)	(81)	(853)
Net change in non-cash working capital from discontinued operations		(37)	17	17	64
		914	605	4,311	1,613
INVESTING ACTIVITIES					
Capital expenditures	(Note 4)	(1,677)	(900)	(5,115)	(3,021)
Proceeds on disposal of property, plant and equipment		282	121	301	363
Corporate (acquisitions) and dispositions	(Note 3)	14	60	(193)	60
Business combination with					

Alberta Energy Company Ltd.		-	-	-	(80)
Equity investments		(3)	-	(161)	-
Net change in investments and other		5	32	(63)	43
Net change in non-cash working capital from continuing operations		29	293	(83)	186
Discontinued operations	(Note 5)	-	(59)	1,585	(146)
		(1,350)	(453)	(3,729)	(2,595)
FINANCING ACTIVITIES					
Issuance of long-term debt		526	760	1,609	1,506
Repayment of long-term debt		-	(1,297)	(963)	(1,206)
Issuance of common shares	(Note 10)	19	27	114	88
Purchase of common shares	(Note 10)	(186)	-	(868)	-
Dividends on common shares		(36)	(30)	(139)	(108)
Other		(8)	(36)	(13)	(53)
Net change in non-cash working capital from continuing operations		22	1	2	(7)
Discontinued operations		-	277	(282)	271
		337	(298)	(540)	491
DEDUCT: FOREIGN EXCHANGE LOSS (GAIN) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		1	-	10	(2)
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		(100)	(146)	32	(489)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		248	262	116	605
CASH AND CASH EQUIVALENTS, END OF PERIOD		$ 148	$ 116	$ 148	$ 116

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

Notes to Consolidated Financial Statements (unaudited)

(All amounts in US$ millions unless otherwise specified)

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, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2002.

2. CHANGE IN ACCOUNTING POLICIES AND PRACTICES

Reporting Currency

The Company has adopted the United States dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American upstream exploration and development companies. The Company uses the current rate method for foreign currency translations. All prior periods have been restated to reflect the United States dollar as the reporting currency.

Preferred Securities

The Company has retroactively adopted the amendments made to the Canadian Institute of Chartered Accountants ("CICA") Handbook section 3860, "Financial Instruments - Disclosure and Presentation". As a result, the preferred securities issued by the Company are now recorded as a liability and included in long-term debt. The effect on the Company's Consolidated Statement of Earnings was to increase net earnings by $6 million (2002 - $2 million decrease). The effect to the Company's Consolidated Balance Sheet is to increase current portion of long-term debt by $97 million, increase long-term debt by $321 million and decrease shareholders' equity by $418 million (2002 - $369 million increase to long-term debt; $289 million decrease to preferred securities of subsidiary; $80 million decrease to shareholders' equity).

Asset Retirement Obligations

The Company has retroactively early adopted the Canadian accounting standard outlined in CICA Handbook section 3110, "Asset Retirement Obligations". This new section requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. The obligations included within the scope of this section are those for which a company faces a legal obligation for settlement or has made promissory estoppel. The initial measurement of the asset retirement obligation is at fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale."

The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation, depletion and amortization.

The Company previously estimated costs of dismantlement, removal, site reclamation, and other similar activities and recorded them into earnings on a unit-of production basis over the remaining life of the proved reserves and accumulated a liability on the Consolidated Balance Sheet. Upon adoption, all prior periods have been restated for the change in accounting policy. The change results in an increase in net earnings of $36 million for the year ended December 31, 2003 (2002 - $34 million increase). The effect of this change on the December 31, 2003 Consolidated Balance Sheet is an increase in property, plant and equipment of $142 million (2002 - $94 million increase), no change in the assets of discontinued operations (2002 - $11 million decrease), an increase in liabilities of $22 million (2002 - $16 million), an increase to retained earnings of $102 million (2002 - $66 million) and an increase in foreign currency translation adjustment of $18 million (2002 - $1 million).

Stock-based Compensation

The Company has early adopted the Canadian accounting standard as outlined in CICA Handbook section 3870, "Stock-based Compensation and Other Stock-based Payments". As allowed by section 3870, this policy has been adopted prospectively, meaning all prior years have not been restated.

The adoption of the new accounting standard for stock-based compensation resulted in the Company recognizing an expense of $18 million in 2003.

Full Cost Accounting

The Company has early adopted CICA Accounting Guideline AcG - 16, "Oil and Gas Accounting - Full Cost". The new guideline modifies how the ceiling test is performed and requires cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost center would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties when determining expected cash flows. There is no impact on the Company's reported financial results as a result of applying the new Accounting Guideline AcG - 16.

Summary of Changes in Accounting Policies and Practices

	2003			2002		
(US$ millions)	As Reported	Change	As Restated	As Reported	Change	As Restated
Consolidated Balance Sheet						
Assets						
Assets of discontinued operations	$ -	$ -	$ -	$ 2,166	$ (11)	$ 2,155
Property, plant and equipment, net	19,403	142	19,545	14,153	94	14,247
Liabilities						
Liabilities of discontinued operations	$ -	$ -	$ -	$ 1,113	$ (13)	$ 1,100
Current portion of long-term debt	190	97	287	134	-	134
Long-term debt	5,767	321	6,088	4,682	369	5,051
Preferred securities of subsidiary	-	-	-	289	(289)	-
Other liabilities & asset retirement obligation	473	(22)	451	357	6	363
Future income taxes	4,318	44	4,362	3,065	23	3,088
Shareholders' Equity						
Preferred securities	$ 418	$ (418)	$ -	$ 80	$ (80)	$ -
Paid in surplus	-	18	18	51	-	51

Retained earnings	5,192	84	5,276	3,457	66	3,523
Foreign currency translation adjustment	606	18	624	(452)	1	(451)
Consolidated Statement of Earnings						
Net Earnings	$ 2,336	$ 24	$ 2,360	$ 780	$ 32	$ 812
Net Earnings per Common Share - Diluted	$ 4.88	$ 0.04	$ 4.92	$ 1.84	$ 0.08	$ 1.92

3. CORPORATE (ACQUISITIONS) AND DISPOSITIONS

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of $116 million.

On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of $91 million. Savannah's operations are in Texas, USA.

These purchases were accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the dates of acquisition. These acquisitions were accounted for as follows:

(US$ millions)	Vintage	Savannah
Working Capital	$ 1	$ 1
Property, Plant and Equipment, net	126	110
Future Income Taxes	(11)	(20)
	$ 116	$ 91

Other dispositions of discontinued operations are disclosed in Note 5.

4. SEGMENTED INFORMATION

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

- Upstream includes the Company's exploration for, and development and production of, natural gas, natural gas liquids and crude oil and other related activities. The Company's Upstream operations are primarily located in Canada, the United States, the United Kingdom and Ecuador. International new ventures exploration is mainly focused on opportunities in Africa, South America and the Middle East.
- Midstream & Marketing includes natural gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activities. These marketing activities include the sale and delivery of produced product and the purchasing of third party product primarily for the optimization of midstream assets, as well as the optimization of transportation arrangements not fully utilized for the Company's own production.

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

In 2003, the Company redefined its business segments to those described above. All prior periods have been restated to conform to the current presentation.

Operations that have been discontinued are disclosed in Note 5.

Results of Operations (For the three months ended December 31)

	Upstream	Midstream & Marketing

(US$ millions)	2003	2002	2003	2002
Revenues				
Revenues, net of royalties	$ 1,676	$ 1,264	$ 1,174	$ 845
Expenses				
Production and mineral taxes	58	41	-	-
Transportation and selling	159	100	11	21
Operating	254	194	83	64
Purchased product	-	-	1,049	720
Depreciation, depletion and amortization	689	429	27	10
Segment Income	$ 516	$ 500	$ 4	$ 30

	Corporate		Consolidated	
	2003	2002	2003	2002
Revenues				
Revenues, net of royalties	$ -	$ 7	$ 2,850	$ 2,116
Expenses				
Production and mineral taxes	-	-	58	41
Transportation and selling	-	-	170	121
Operating	-	-	337	258
Purchased product	-	-	1,049	720
Depreciation, depletion and amortization	9	13	725	452
Segment Income	$ (9)	$ (6)	511	524
Administrative			52	48
Interest, net			85	119
Accretion of asset retirement obligation			4	4
Foreign exchange (gain) loss			(165)	3
Stock-based compensation			6	-
Gain on corporate disposition			-	(33)
			(18)	141
Net Earnings Before Income Tax			529	383
Income tax expense			103	135
Net Earnings from Continuing Operations			$ 426	$ 248

Geographic and Product Information
(For the three months ended December 31)

	North America					
Upstream	Produced Gas and NGLs					
	Canada		United States		Crude Oil	
(US$ millions)	2003	2002	2003	2002	2003	2002
Revenues						
Revenues, net of royalties	$ 892	$ 695	$ 298	$ 204	$ 239	$ 235
Expenses						
Production and						

mineral taxes	19	12	27	17	4	7
Transportation and selling	81	57	30	22	21	13
Operating	84	83	17	10	76	57
Depreciation, depletion and amortization	297	199	82	83	125	68
Segment Income	$ 411	$ 344	$ 142	$ 72	$ 13	$ 90

	Ecuador		U.K. North Sea		Other		Total Upstream	
	2003	2002	2003	2002	2003	2002	2003	2002
Revenues								
Revenues, net of royalties	$ 169	$ 79	$ 45	$ 22	$ 33	$ 29	$1,676	$1,264
Expenses								
Production and mineral taxes	8	5	-	-	-	-	58	41
Transportation and selling	21	6	6	2	-	-	159	100
Operating	33	18	8	4	36	22	254	194
Depreciation, depletion and amortization	72	24	21	11	92	44	689	429
Segment Income	$ 35	$ 26	$ 10	$ 5	$ (95)	$ (37)	$ 516	$ 500

Midstream & Marketing

	Midstream		Marketing(*)		Total Midstream & Marketing	
(US$ millions)	2003	2002	2003	2002	2003	2002
Revenues						
Revenues	$ 435	$ 193	$ 739	$ 652	$ 1,174	$ 845
Expenses						
Transportation and selling	-	-	11	21	11	21
Operating	73	59	10	5	83	64
Purchased product	339	90	710	630	1,049	720
Depreciation, depletion and amortization	22	3	5	7	27	10
Segment Income	$ 1	$ 41	$ 3	$ (11)	$ 4	$ 30

(*) Includes transportation cost optimization 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.

Results of Operations (For the year ended December 31)

	Upstream		Midstream & Marketing	
(US$ millions)	2003	2002	2003	2002

Revenues				
Revenues, net of royalties	$ 6,327	$ 3,674	$ 3,887	$ 2,594
Expenses				
Production and mineral taxes	189	119	-	-
Transportation and selling	490	277	55	87
Operating	973	626	324	187
Purchased product	-	-	3,455	2,200
Depreciation, depletion and amortization	2,133	1,233	48	36
Segment Income	$ 2,542	$ 1,419	$ 5	$ 84

	Corporate		Consolidated	
	2003	2002	2003	2002
Revenues				
Revenues, net of royalties	$ 2	$ 8	$ 10,216	$ 6,276
Expenses				
Production and mineral taxes	-	-	189	119
Transportation and selling	-	-	545	364
Operating	-	-	1,297	813
Purchased product	-	-	3,455	2,200
Depreciation, depletion and amortization	41	35	2,222	1,304
Segment Income	$ (39)	$ (27)	2,508	1,476
Administrative			173	119
Interest, net			287	290
Accretion of asset retirement obligation			19	13
Foreign exchange (gain) loss			(601)	(14)
Stock-based compensation			18	-
Gain on corporate disposition			-	(33)
			(104)	375
Net Earnings Before Income Tax			2,612	1,101
Income tax expense			445	366
Net Earnings from Continuing Operations			$ 2,167	$ 735

Geographic and Product Information
(For the year ended December 31)

	North America					
Upstream	Produced Gas and NGLs					
	Canada		United States		Crude Oil	
(US$ millions)	2003	2002	2003	2002	2003	2002
Revenues						
Revenues, net of royalties	$ 3,523	$ 1,971	$ 1,143	$ 454	$ 951	$ 825
Expenses						
Production and						

mineral taxes	52	50	108	35	4	20
Transportation and selling	274	151	86	59	69	35
Operating	342	255	60	35	300	201
Depreciation, depletion and amortization	1,075	625	293	202	436	237
Segment Income	$ 1,780	$ 890	$ 596	$ 123	$ 142	$ 332

	Ecuador		U.K. North Sea		Other		Total Upstream	
	2003	2002	2003	2002	2003	2002	2003	2002
Revenues								
Revenues, net of royalties	$ 412	$ 245	$ 118	$ 103	$ 180	$ 76	$6,327	$3,674
Expenses								
Production and mineral taxes	25	14	-	-	-	-	189	119
Transportation and selling	45	21	16	11	-	-	490	277
Operating	83	53	18	11	170	71	973	626
Depreciation, depletion and amortization	159	79	74	39	96	51	2,133	1,233
Segment Income	$ 100	$ 78	$ 10	$ 42	$ (86)	$ (46)	$2,542	$1,419

Midstream & Marketing	Midstream		Marketing(*)		Total Midstream & Marketing	
(US$ millions)	2003	2002	2003	2002	2003	2002
Revenues						
Revenues	$ 1,084	$ 440	$ 2,803	$ 2,154	$ 3,887	$ 2,594
Expenses						
Transportation and selling	-	-	55	87	55	87
Operating	261	174	63	13	324	187
Purchased product	762	169	2,693	2,031	3,455	2,200
Depreciation, depletion and amortization	40	24	8	12	48	36
Segment Income	$ 21	$ 73	$ (16)	$ 11	$ 5	$ 84

(*) Includes transportation cost optimization 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.

Capital Expenditures

	Three Months Ended December 31		Year Ended December 31	
(US$ millions)	2003	2002	2003	2002

Upstream				
Canada	$ 911	$ 490	$ 3,198	$ 1,388
United States	342	211	968	1,176
Ecuador	93	61	265	168
United Kingdom	178	17	223	82
Other Countries	15	75	78	117
	1,539	854	4,732	2,931
Midstream & Marketing	69	22	276	47
Corporate	69	24	107	43
Total	$ 1,677	$ 900	$ 5,115	$ 3,021

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
	As at December 31,		As at December 31,	
(US$ millions)	2003	2002	2003	2002
Upstream	$ 18,532	$ 13,656	$ 21,742	$ 16,042
Midstream & Marketing	784	470	1,879	1,403
Corporate	229	121	489	312
Assets of Discontinued Operations			-	2,155
Total	$ 19,545	$ 14,247	$ 24,110	$ 19,912

5. DISCONTINUED OPERATIONS

On February 28, 2003, the Company completed the sale of its 10 percent working interest in the Syncrude Joint Venture ("Syncrude") to Canadian Oil Sands Limited for net cash consideration of C$1,026 million (US$690 million). 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 net cash consideration of C$427 million (US$309 million). This transaction completed 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 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 C$1.6 billion (US$1 billion), including assumption of related long-term debt by the purchaser, and recorded an after-tax gain on sale of C$263 million (US$169 million).

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.

The following tables present the effect of the discontinued operations on the Consolidated Financial Statements:

Consolidated Statement of Earnings

For the three months ended December 31

	Syncrude		Merchant Energy		Midstream-Pipelines		Total	
(US$ millions)	2003	2002	2003	2002	2003	2002	2003	2002
Revenues, Net of Royalties	$ -	$ 85	$ -	$ (6)	$ -	$ 40	$ -	$ 119
Expenses								
Transportation and selling	-	1	-	-	-	-	-	1
Operating	-	33	-	-	-	16	-	49
Purchased product	-	-	-	(6)	-	-	-	(6)
Depreciation, depletion and amortization	-	6	-	(1)	-	3	-	8
Administrative	-	-	-	1	-	-	-	1
Interest, net	-	1	-	-	-	5	-	6
Loss on discontinuance	-	-	-	4	-	-	-	4
	-	41	-	(2)	-	24	-	63
Net Earnings (Loss) Before Income Tax	-	44	-	(4)	-	16	-	56
Income tax expense (recovery)	-	17	-	(1)	-	6	-	22
Net Earnings (Loss) from Discontinued Operations	$ -	$ 27	$ -	$ (3)	$ -	$ 10	$ -	$ 34

Consolidated Statement of Earnings	For the year ended December 31							
	Syncrude(*)		Merchant Energy		Midstream-Pipelines(*)		Total	
(US$ millions)	2003	2002	2003	2002	2003	2002	2003	2002
Revenues, Net of Royalties	$ 87	$ 232	$ -	$ 922	$ -	$ 135	$ 87	$1,289
Expenses								
Transportation and selling	2	3	-	-	-	-	2	3
Operating	46	105	-	-	-	50	46	155
Purchased product	-	-	-	931	-	-	-	931
Depreciation, depletion and amortization	7	16	-	-	-	18	7	34
Administrative	-	-	-	22	-	-	-	22
Interest, net	-	1	-	-	-	19	-	20
Foreign exchange								

(gain)	-	-	-	-	-	(3)	-	(3)
(Gain) loss on discontinuance		-	-	19	(220)	-	(220)	19
	55	125	-	972	(220)	84	(165)	1,181
Net Earnings (Loss) Before Income Tax	32	107	-	(50)	220	51	252	108
Income tax expense (recovery)	8	28	-	(17)	51	20	59	31
Net Earnings (Loss) from Discontinued Operations	$ 24	$ 79	$ -	$ (33)	$ 169	$ 31	$ 193	$ 77

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

Consolidated Balance Sheet

	As at December 31							
	Syncrude		Merchant Energy		Midstream-Pipelines		Total	
(US$ millions)	2003	2002	2003	2002	2003	2002	2003	2002
Assets								
Cash and cash equivalents	$ -	$ 18	$ -	$ -	$ -	$ 43	$ -	$ 61
Accounts receivable and accrued revenues	-	41	-	-	-	20	-	61
Inventories	-	9	-	-	-	1	-	10
	-	68	-	-	-	64	-	132
Property, plant and equipment, net	-	884	-	-	-	517	-	1,401
Investments and other assets	-	-	-	-	-	237	-	237
Goodwill	-	264	-	-	-	121	-	385
	-	1,216	-	-	-	939	-	2,155
Liabilities								
Accounts payable and accrued liabilities	-	68	-	3	-	25	-	96
Income tax payable	-	(4)	-	-	-	11	-	7
Short-term debt	-	277	-	-	-	-	-	277
Current portion of long-term debt	-	-	-	-	-	15	-	15
	-	341	-	3	-	51	-	395
Long-term debt	-	-	-	-	-	365	-	365

Future income taxes	-	236	-	-	-	104	-	340
	-	577	-	3	-	520	-	1,100
Net Assets of Discontinued Operations	$ -	$ 639	$ -	$ (3)	$ -	$ 419	$ -	$1,055

6. FOREIGN EXCHANGE (GAIN) LOSS

	Three Months Ended December 31		Year Ended December 31	
(US$ millions)	2003	2002	2003	2002
Unrealized Foreign Exchange (Gain) on Translation of U.S. Dollar Debt Issued in Canada	$ (141)	$ (8)	$ (545)	$ (23)
Other Foreign Exchange (Gain) Loss	(24)	11	(56)	9
	$ (165)	$ 3	$ (601)	$ (14)

7. INCOME TAXES

	Three Months Ended December 31		Year Ended December 31	
(US$ millions)	2003	2002	2003	2002
Provision for Income Taxes				
Current				
Canada	$ (118)	$ (108)	$ (136)	$ (26)
United States	29	-	39	(31)
Ecuador	18	8	39	17
United Kingdom	(3)	(8)	-	-
Other Countries	1	1	2	2
	(73)	(107)	(56)	(38)
Future	173	245	860	424
Future tax rate reductions(*)	3	(3)	(359)	(20)
	$ 103	$ 135	$ 445	$ 366

(*) During the second quarter of 2003, both the Canadian federal and Alberta governments substantively enacted income tax rate reductions previously announced. The reduced rates were passed into law during the fourth quarter of 2003.

8. LONG-TERM DEBT

(US$ millions)	As at December 31, 2003	As at December 31, 2002
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	$ 1,425	$ 879
Unsecured notes and debentures	1,335	1,155
Preferred securities	252	206

	3,012	2,240
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	417	441
Unsecured notes and debentures	2,713	2,284
Preferred securities	150	150
	3,280	2,875
Increase in Value of Debt Acquired(*)	83	70
Current Portion of Long-Term Debt	(287)	(134)
	$ 6,088	$ 5,051

(*) 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 28 years.

9. ASSET RETIREMENT OBLIGATION

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

	As at December 31,	
(US$ millions)	2003	2002
Asset Retirement Obligation, Beginning of Year	$ 309	$ 163
Liabilities Incurred	64	146
Liabilities Settled	(23)	(13)
Accretion Expense	19	13
Other	61	-
Asset Retirement Obligation, End of Year	$ 430	$ 309

The total undiscounted amount of estimated cash flows required to settle the obligation is $3,223 million (2002 - $2,516 million), which has been discounted using a credit-adjusted risk free rate of 5.9 percent. Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at the time of removal.

10. SHARE CAPITAL

	December 31, 2003		December 31, 2002	
(millions)	Number	Amount	Number	Amount
Common Shares Outstanding, Beginning of Year	478.9	$ 5,511	254.9	$ 142
Shares Issued to AEC Shareholders	-	-	218.5	5,281
Shares Issued under Option Plans	5.5	114	5.5	88
Shares Repurchased	(23.8)	(320)	-	-
Common Shares Outstanding, End of Year	460.6	$ 5,305	478.9	$ 5,511

During the quarter, the Company purchased, for cancellation, 5,215,000 Common Shares (Year-to-date - 23,839,400 Common Shares) for total consideration of approximately C$244 million (US$186 million) (Year-to-date - C$1,184 million; US$868 million). Of the C$1,184 million (US$868 million) paid this year, C$437 million (US$320 million) was charged to share capital, C$102 million (US$80 million) was charged to paid in surplus and C$645 million (US$468 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 after the grant date.

The following tables summarize the information about options to purchase common shares at December 31, 2003:

	Stock Options (millions)	Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	29.6	39.74
Granted under EnCana Plans	6.4	47.97
Exercised	(5.5)	29.11
Forfeited	(1.7)	41.18
Outstanding, End of Year	28.8	43.13
Exercisable, End of Year	15.6	38.92

	Outstanding Options			Exercisable Options	
Range of Exercise Price (C$)	Number of Options Outstanding (millions)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price(C$)	Number of Options Out-standing (millions)	Weighted Average Exercise Price(C$)
13.50 to 19.99	1.5	0.9	18.86	1.5	18.86
20.00 to 24.99	1.3	1.5	22.38	1.3	22.38
25.00 to 29.99	2.2	1.5	26.49	2.2	26.49
30.00 to 43.99	1.3	2.2	38.89	1.2	38.52
44.00 to 53.00	22.5	3.7	47.93	9.4	47.63
	28.8	2.8	43.13	15.6	38.92

As described in Note 2, the Company recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted in 2003 to employees and directors using the fair-value method. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted in prior years, pro forma Net Earnings and Net Earnings per Common Share in 2003 would have been $2,326 million; $4.91 per common share - basic; $4.85 per common share - diluted (2002 - $761 million; $1.82 per common share - basic; $1.80 per common share - diluted).

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

	Year Ended December 31 2003	Year Ended December 31 2002
Weighted Average Fair Value of Options Granted (C$)	$ 12.21	$ 13.31
Risk Free Interest Rate	3.87%	4.29%
Expected Lives (years)	3.00	3.00
Expected Volatility	0.33	0.35
Annual Dividend per Share (C$)	$ 0.40	$ 0.40

11. PER SHARE AMOUNTS

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

(millions)	Three Months Ended March 31 2003	June 30 2003	September 30 2003	December 31 2003	December 31 2002	Year Ended December 31 2003	Year Ended December 31 2002
Weighted Average Common Shares Outstanding - Basic	479.9	480.6	473.4	462.3	477.9	474.1	417.8
Effect of Dilutive Securities	4.4	3.8	4.5	3.6	4.7	5.6	4.8
Weighted Average Common Shares Outstanding - Diluted	484.3	484.4	477.9	465.9	482.6	479.7	422.6

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

(US$ millions)	As at December 31, 2003
Commodity Price Risk	
Natural gas	$ 57
Crude oil	(279)
Gas storage optimization	(25)
Power	4
Foreign Currency Risk	7
Interest Rate Risk	44
	$ (192)

Information with respect to power, 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. No significant new contracts have been entered into as at December 31, 2003.

Natural Gas

At December 31, 2003, the Company's gas risk management activities had an unrecognized gain of $57 million. The contracts were as follows:

	Notional Volumes (MMcf/d)	Physical/ Financial	Term	Price		Unrecognized Gain/ (Loss) (US$ millions)
Fixed Price Contracts						
Sales Contracts						
Fixed AECO price	453	Financial	2004	6.20	C$/mcf	$ 5
NYMEX Fixed price	732	Financial	2004	5.13	US$/mcf	(86)
Chicago Fixed price	40	Financial	2004	5.41	US$/mcf	(1)
AECO Collars	71	Financial	2004	5.34-7.52	C$/mcf	2
NYMEX Collars	50	Physical	2004	2.46-4.90	US$/mcf	(16)
NYMEX Collars	50	Physical	2005	2.46-4.90	US$/mcf	(13)
NYMEX Collars	46	Physical	2006-2007	2.46-4.90	US$/mcf	(20)
Basis Contracts						
Sales Contracts						
Fixed NYMEX to AECO basis	343	Financial	2004	(0.54)	US$/mcf	22
Fixed NYMEX to Rockies basis	255	Financial	2004	(0.48)	US$/mcf	18
Fixed NYMEX to Rockies basis	413	Physical	2004	(0.50)	US$/mcf	26
Fixed NYMEX to San Juan basis	60	Financial	2004	(0.63)	US$/mcf	1
Fixed NYMEX to San Juan basis	50	Physical	2004	(0.64)	US$/mcf	1
Fixed Rockies to CIG basis	38	Financial	2004	(0.10)	US$/mcf	-
Fixed NYMEX to AECO basis	877	Financial	2005	(0.66)	US$/mcf	6
Fixed NYMEX to Rockies basis	283	Financial	2005	(0.49)	US$/mcf	16
Fixed NYMEX to Rockies basis	393	Physical	2005	(0.47)	US$/mcf	26
Fixed NYMEX to San Juan basis	75	Financial	2005	(0.63)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	50	Physical	2005	(0.64)	US$/mcf	(1)
Fixed Rockies to CIG basis	50	Financial	2005	(0.10)	US$/mcf	1
Fixed NYMEX to AECO basis	402	Financial	2006-2008	(0.65)	US$/mcf	24

Fixed NYMEX to Rockies basis	175	Financial	2006-2008	(0.57)	US$/mcf	13
Fixed NYMEX to Rockies basis	207	Physical	2006-2007	(0.49)	US$/mcf	22
Fixed NYMEX to San Juan basis	62	Financial	2006	(0.62)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	42	Physical	2006	(0.64)	US$/mcf	(1)
Fixed Rockies to CIG basis	31	Financial	2006-2007	(0.10)	US$/mcf	-
Purchase Contracts						
Fixed NYMEX to AECO basis	47	Financial	2004	(0.80)	US$/mcf	(3)
						40
Gas Marketing Financial Positions(1)						(2)
Gas Marketing Physical Positions(1)						19
						$ 57

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

Crude Oil

As at December 31, 2003, the Company's oil risk management activities had an unrecognized loss of $279 million. The contracts were as follows:

	Notional Volumes (bbl/d)	Term	Average Price (US$/bbl)	Unrecognized Gain/ (Loss) (US$ millions)
Fixed WTI NYMEX Price	62,500	2004	23.13	$ (162)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(115)
3-way Put Spread	10,000	2005	20.00/25.00/28.77	(3)
				(280)
Crude Oil Marketing Financial Positions(1)				(2)
Crude Oil Marketing Physical Positions(1)				3
				$ (279)

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

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 inventories.

As at December 31, 2003, the unrecognized loss on gas storage optimization risk management activities was $25 million, which was as follows:

	Notional Volumes (bcf)	Price (US$/mcf)	Unrecognized Gain/ (Loss) (US$ millions)
Financial Instruments			
Purchases	286.7	5.63	$ 109
Sales	312.4	5.69	(132)
			(23)
Physical Contracts			(2)
			$ (25)

At December 31, 2003, the unrecognized loss on physical contracts of $2 million was more than offset by unrealized gains on physical inventory in storage.

13. RECLASSIFICATION

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

Interim Consolidated Financial Statements
(unaudited)
For the period ended December 31, 2003
EnCana Corporation
CANADIAN DOLLARS

Notice to Reader

These unaudited Interim Consolidated Financial Statements for the period ended December 31, 2003 have been provided for this transition period as EnCana moves to U.S. dollar reporting.

PREPARED IN C$

Interim Report
For the period ended December 31, 2003
EnCana Corporation

CONSOLIDATED STATEMENT OF EARNINGS

(unaudited) (C$ millions, except per share amounts)		December 31 Three Months Ended 2003	2002	Year Ended 2003	2002
			(restated - Note 2)		(restated - Note 2)
REVENUES, NET OF ROYALTIES	(Note 4)	$ 3,751	$ 3,322	$ 14,316	$ 9,831
EXPENSES	(Note 4)				
Production and mineral taxes		77	64	264	185
Transportation and selling		223	190	760	570
Operating		443	405	1,815	1,274
Purchased product		1,381	1,131	4,839	3,448
Depreciation, depletion and amortization		954	710	3,090	2,042
Administrative		69	76	241	187
Interest, net		112	187	401	453
Accretion of asset					

retirement obligation	(Note 9)	5	7	27	21
Foreign exchange (gain) loss	(Note 6)	(191)	4	(785)	(23)
Stock-based compensation	(Note 2)	8	-	24	-
Gain on corporate disposition		-	(51)	-	(51)
		3,081	2,723	10,676	8,106
NET EARNINGS BEFORE INCOME TAX		670	599	3,640	1,725
Income tax expense	(Note 7)	136	212	664	573
NET EARNINGS FROM CONTINUING OPERATIONS		534	387	2,976	1,152
NET EARNINGS FROM DISCONTINUED OPERATIONS	(Note 5)	-	56	298	123
NET EARNINGS		$ 534	$ 443	$ 3,274	$ 1,275
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	(Note 11)				
Basic		$ 1.16	$ 0.81	$ 6.28	$ 2.76
Diluted		$ 1.15	$ 0.80	$ 6.20	$ 2.73
NET EARNINGS PER COMMON SHARE	(Note 11)				
Basic		$ 1.16	$ 0.93	$ 6.91	$ 3.05
Diluted		$ 1.15	$ 0.92	$ 6.83	$ 3.02

EnCana Corporation

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(unaudited) (C$ millions)		Year Ended December 31 2003	Year Ended December 31 2002
			(restated - Note 2)
RETAINED EARNINGS, BEGINNING OF YEAR			
As previously reported		$ 4,684	$ 3,630
Retroactive adjustment for changes in accounting policies	(Note 2)	103	49
As restated		4,787	3,679
Net Earnings		3,274	1,275
Dividends on Common Shares		(190)	(167)
Charges for Normal Course Issuer Bid	(Note 10)	(645)	-
RETAINED EARNINGS, END OF YEAR		$ 7,226	$ 4,787

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED BALANCE SHEET

(unaudited) (C$ millions)		As at December 31, 2003	As at December 31, 2002
			(restated - Note 2)
ASSETS			
Current Assets			
Cash and cash equivalents		$ 191	$ 183
Accounts receivable and accrued revenues		1,766	1,987
Inventories		740	443
Assets of discontinued operations	(Note 5)	-	3,404
		2,697	6,017
Property, Plant and Equipment, net	(Note 4)	25,259	22,504
Investments and Other Assets		732	462
Goodwill		2,469	2,469
	(Note 4)	$ 31,157	$ 31,452
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,040	$ 2,282
Income tax payable		84	20
Current portion of long-term debt	(Note 8)	372	212
Liabilities of discontinued operations	(Note 5)	-	1,738
		2,496	4,252
Long-Term Debt	(Note 8)	7,866	7,978
Other Liabilities		27	86
Asset Retirement Obligation	(Note 9)	556	488
Future Income Taxes		5,637	4,877
		16,582	17,681
Shareholders' Equity			
Share capital	(Note 10)	8,456	8,732
Share options, net		92	133
Paid in surplus		24	61
Retained earnings		7,226	4,787
Foreign currency translation adjustment		(1,223)	58
		14,575	13,771
		$ 31,157	$ 31,452

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

	December 31			
	Three Months Ended		Year Ended	
(unaudited) (C$ millions)	2003	2002	2003	2002
		(restated		(restated

			- Note 2)		- Note 2)
OPERATING ACTIVITIES					
Net earnings from continuing operations		$ 534	$ 387	$ 2,976	$ 1,152
Depreciation, depletion and amortization		954	710	3,090	2,042
Future income taxes	(Note 7)	232	379	735	632
Unrealized foreign exchange (gain)		(159)	(13)	(704)	(37)
Accretion of asset retirement obligation		5	7	27	21
Other		37	(101)	84	(250)
Cash flow from continuing operations		1,603	1,369	6,208	3,560
Cash flow from discontinued operations		49	95	54	237
Cash flow		1,652	1,464	6,262	3,797
Net change in other assets and liabilities		(2)	(2)	(117)	(27)
Net change in non-cash working capital from continuing operations		(406)	(544)	(161)	(1,351)
Net change in non-cash working capital from discontinued operations		(49)	26	29	99
		1,195	944	6,013	2,518
INVESTING ACTIVITIES					
Capital expenditures	(Note 4)	(2,220)	(1,413)	(7,100)	(4,724)
Proceeds on disposal of property, plant and equipment		375	190	402	566
Corporate (acquisitions) and dispositions	(Note 3)	18	93	(289)	93
Business combination with Alberta Energy Company Ltd.		-	-	-	(128)
Equity investments		(4)	-	(226)	-
Net change in investments and other		7	50	(89)	67
Net change in non-cash working capital from continuing operations		38	460	(135)	293
Discontinued operations	(Note 5)	-	(93)	2,372	(229)
		(1,786)	(713)	(5,065)	(4,062)
FINANCING ACTIVITIES					
Issuance of					

long-term debt		696	1,189	2,197	2,354
Repayment of long-term debt		-	(2,026)	(1,445)	(1,886)
Issuance of common shares	(Note 10)	25	43	161	139
Purchase of common shares	(Note 10)	(244)	-	(1,184)	-
Dividends on common shares		(47)	(47)	(190)	(167)
Other		(9)	(57)	(16)	(82)
Net change in non-cash working capital from continuing operations		29	1	-	(12)
Discontinued operations		-	434	(438)	425
		450	(463)	(915)	771
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		3	-	25	7
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		(144)	(232)	8	(780)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		335	415	183	963
CASH AND CASH EQUIVALENTS, END OF PERIOD		$ 191	$ 183	$ 191	$ 183

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

Notes to Consolidated Financial Statements (unaudited)

(All amounts in C$ millions unless otherwise specified)

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, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2002.

2. CHANGE IN ACCOUNTING POLICIES AND PRACTICES

Preferred Securities

The Company has retroactively adopted the amendments made to Canadian Institute of Chartered Accountants ("CICA") Handbook section 3860, "Financial Instruments - Disclosure and Presentation". As a result, all of the preferred securities issued by the Company are now recorded as a liability and included in long-term debt. The effect on the Company's Consolidated Statement of Earnings was to increase net earnings by $9 million (2002 - $3 million decrease). The effect to the Company's Consolidated Balance Sheet is to increase current portion of long-term debt by $126 million, increase long-term debt by $415 million and decrease shareholders' equity by $541 million (2002 - $583 million increase to long-term debt; $457 million decrease to preferred securities of subsidiary; $126 million decrease to shareholders' equity).

Asset Retirement Obligations

The Company has retroactively early adopted the Canadian accounting standard outlined in CICA Handbook section 3110, "Asset Retirement Obligations". This new section requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. The obligations included within the scope of this section are those for which a company faces a legal obligation for settlement or has made promissory estoppel. The initial measurement of the asset retirement obligation is at fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale".

The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation, depletion and amortization.

The Company previously estimated costs of dismantlement, removal, site reclamation, and other similar activities and recorded them into earnings on a unit-of production basis over the remaining life of the proved reserves and accumulated a liability on the Consolidated Balance Sheet. Upon adoption, all prior periods have been restated for the change in accounting policy. The change results in an increase in net earnings of $50 million for the year ended December 31, 2003 (2002 - $54 million increase). The effect of this change on the December 31, 2003 Consolidated Balance Sheet is an increase in property, plant and equipment of $183 million (2002 - $148 million increase), no change in the assets of discontinued operations (2002 - $18 million decrease), an increase in liabilities of $30 million (2002 - $27 million) and an increase to retained earnings of $153 million (2002 - $103 million).

Stock-based Compensation

The Company has early adopted the Canadian accounting standard as outlined in CICA Handbook section 3870, "Stock-based Compensation and Other Stock-based Payments". As allowed by section 3870, this policy has been adopted prospectively, meaning all prior years have not been restated.

The adoption of the new accounting standard for stock-based compensation resulted in the Company recognizing an expense of $24 million in 2003.

Full Cost Accounting

The Company has early adopted CICA Accounting Guideline AcG - 16, "Oil and Gas Accounting - Full Cost". The new guideline modifies how the ceiling test is performed and requires cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost center would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties when determining expected cash flows. There is no impact on the Company's reported financial results as a result of applying the new Accounting Guideline AcG - 16.

Summary of Changes in Accounting Policies and Practices

	2003			2002	
	As		As	As		As

(C$ millions)	Reported	Change	Restated	Reported	Change	Restated
Consolidated Balance Sheet						
Assets						
Assets of discontinued operations	$ -	$ -	$ -	$ 3,422	$ (18)	$ 3,404
Property, plant and equipment, net	25,076	183	25,259	22,356	148	22,504
Liabilities						
Liabilities of discontinued operations	$ -	$ -	$ -	$ 1,758	$ (20)	$ 1,738
Current portion of long-term debt	246	126	372	212	-	212
Long-term debt	7,451	415	7,866	7,395	583	7,978
Preferred securities of subsidiary	-	-	-	457	(457)	-
Other liabilities & asset retirement obligation	611	(28)	583	564	10	574
Future income taxes	5,579	58	5,637	4,840	37	4,877
Shareholders' Equity						
Preferred securities	$ 541	$ (541)	$ -	$ 126	$ (126)	$ -
Paid in surplus	-	24	24	61	-	61
Retained earnings	7,097	129	7,226	4,684	103	4,787
Consolidated Statement of Earnings						
Net Earnings	$ 3,239	$ 35	$ 3,274	$ 1,224	$ 51	$ 1,275
Net Earnings per Common Share - Diluted	$ 6.78	$ 0.05	$ 6.83	$ 2.89	$ 0.13	$ 3.02

3. CORPORATE (ACQUISITIONS) AND DISPOSITIONS

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of $179 million (US$116 million).

On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of $128 million (US$91 million). Savannah's operations are in Texas, USA.

These purchases were accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the dates of acquisition. These acquisitions were accounted for as follows:

(C$ millions)	Vintage	Savannah
Working Capital	$ 2	$ 1
Property, Plant and Equipment, net	194	155
Future Income Taxes	(17)	(28)
	$ 179	$ 128

Other dispositions of discontinued operations are disclosed in Note 5.

4. SEGMENTED INFORMATION

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

- Upstream includes the Company's exploration for, and development and production of, natural gas, natural gas liquids and crude oil and other related activities. The Company's Upstream operations are primarily located in Canada, the United States, the United Kingdom and Ecuador. International new ventures exploration is mainly focused on opportunities in Africa, South America and the Middle East.
- Midstream & Marketing includes natural gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activities. These marketing activities include the sale and delivery of produced product and the purchasing of third party product primarily for the optimization of midstream assets, as well as the optimization of transportation arrangements not fully utilized for the Company's own production.

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

In 2003, the Company redefined its business segments to those described above. All prior periods have been restated to conform to the current presentation.

Operations that have been discontinued are disclosed in Note 5.

Results of Operations (For the three months ended December 31)

	Upstream		Midstream & Marketing	
(C$ millions)	2003	2002	2003	2002
Revenues				
Revenues, net of royalties	$ 2,206	$ 1,984	$ 1,545	$ 1,327
Expenses				
Production and mineral taxes	77	64	-	-
Transportation and selling	209	157	14	33
Operating	334	304	109	101
Purchased product	-	-	1,381	1,131
Depreciation, depletion and amortization	906	673	36	16
Segment Income	$ 680	$ 786	$ 5	$ 46

	Corporate		Consolidated	
	2003	2002	2003	2002
Revenues				
Revenues, net of royalties	$ -	$ 11	$ 3,751	$ 3,322
Expenses				
Production and mineral taxes	-	-	77	64
Transportation and selling	-	-	223	190
Operating	-	-	443	405
Purchased product	-	-	1,381	1,131
Depreciation, depletion and amortization	12	21	954	710
Segment Income	$ (12)	$ (10)	673	822
Administrative			69	76

Interest, net		112	187
Accretion of asset retirement obligation		5	7
Foreign exchange (gain) loss		(191)	4
Stock-based compensation		8	-
Gain on corporate disposition		-	(51)
		3	223
Net Earnings Before Income Tax		670	599
Income tax expense		136	212
Net Earnings from Continuing Operations		$ 534	$ 387

Geographic and Product Information
(For the three months ended December 31)

Upstream	North America					
	Produced Gas and NGLs					
	Canada		United States		Crude Oil	
(C$ millions)	2003	2002	2003	2002	2003	2002
Revenues						
Revenues, net of royalties	$ 1,174	$ 1,091	$ 392	$ 320	$ 315	$ 370
Expenses						
Production and mineral taxes	25	19	36	27	5	10
Transportation and selling	107	89	40	34	27	20
Operating	110	130	23	16	100	89
Depreciation, depletion and amortization	390	312	108	130	164	107
Segment Income	$ 542	$ 541	$ 185	$ 113	$ 19	$ 144

	Ecuador		U.K. North Sea		Other		Total Upstream	
	2003	2002	2003	2002	2003	2002	2003	2002
Revenues								
Revenues, net of royalties	$ 222	$ 124	$ 59	$ 34	$ 44	$ 45	$2,206	$1,984
Expenses								
Production and mineral taxes	11	8	-	-	-	-	77	64
Transportation and selling	27	10	8	4	-	-	209	157
Operating	43	28	11	7	47	34	334	304
Depreciation, depletion and amortization	95	37	28	17	121	70	906	673
Segment Income	$ 46	$ 41	$ 12	$ 6	$(124)	$ (59)	$ 680	$ 786

Midstream & Marketing Total Midstream

(C$ millions)	Midstream		Marketing (*)		& Marketing	
	2003	2002	2003	2002	2003	2002
Revenues						
Revenues	$ 573	$ 303	$ 972	$ 1,024	$ 1,545	$ 1,327
Expenses						
Transportation and selling	-	-	14	33	14	33
Operating	96	93	13	8	109	101
Purchased product	446	142	935	989	1,381	1,131
Depreciation, depletion and amortization	29	5	7	11	36	16
Segment Income	$ 2	$ 63	$ 3	$ (17)	$ 5	$ 46

(*) Includes transportation cost optimization 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.

Results of Operations (For the year ended December 31)

(C$ millions)	Upstream		Midstream & Marketing	
	2003	2002	2003	2002
Revenues				
Revenues, net of royalties	$ 8,866	$ 5,755	$ 5,446	$ 4,062
Expenses				
Production and mineral taxes	264	185	-	-
Transportation and selling	683	434	77	136
Operating	1,360	980	455	294
Purchased product	-	-	4,839	3,448
Depreciation, depletion and amortization	2,967	1,930	66	57
Segment Income	$ 3,592	$ 2,226	$ 9	$ 127

	Corporate		Consolidated	
	2003	2002	2003	2002
Revenues				
Revenues, net of royalties	$ 4	$ 14	$ 14,316	$ 9,831
Expenses				
Production and mineral taxes	-	-	264	185
Transportation and selling	-	-	760	570
Operating	-	-	1,815	1,274
Purchased product	-	-	4,839	3,448
Depreciation, depletion and amortization	57	55	3,090	2,042
Segment Income	$ (53)	$ (41)	3,548	2,312
Administrative			241	187
Interest, net			401	453
Accretion of asset retirement obligation			27	21

Foreign exchange (gain) loss	(785)	(23)
Stock-based compensation	24	-
Gain on corporate disposition	-	(51)
	(92)	587
Net Earnings Before Income Tax	3,640	1,725
Income tax expense	664	573
Net Earnings from Continuing Operations	$ 2,976	$ 1,152

Geographic and Product Information (For the year ended December 31)

Upstream	North America					
	Produced Gas and NGLs					
	Canada		United States		Crude Oil	
(C$ millions)	2003	2002	2003	2002	2003	2002
Revenues						
Revenues, net of royalties	$4,945	$3,089	$1,604	$ 711	$1,331	$1,294
Expenses						
Production and mineral taxes	70	78	151	55	7	31
Transportation and selling	384	235	119	91	96	55
Operating	480	398	85	54	420	315
Depreciation, depletion and amortization	1,501	977	409	315	608	372
Segment Income	$2,510	$1,401	$ 840	$ 196	$ 200	$ 521

	Ecuador		U.K. North Sea		Other		Total Upstream	
	2003	2002	2003	2002	2003	2002	2003	2002
Revenues								
Revenues, net of royalties	$ 570	$ 382	$ 164	$ 160	$ 252	$ 119	$8,866	$5,755
Expenses								
Production and mineral taxes	36	21	-	-	-	-	264	185
Transportation and selling	60	34	24	19	-	-	683	434
Operating	113	83	24	18	238	112	1,360	980
Depreciation, depletion and amortization	218	123	103	63	128	80	2,967	1,930
Segment Income	$ 143	$ 121	$ 13	$ 60	$ (114)	$ (73)	$3,592	$2,226

Midstream & Marketing	Midstream		Marketing (*)		Total Midstream & Marketing	
(C$ millions)	2003	2002	2003	2002	2003	2002

Revenues						
Revenues	$1,513	$ 689	$3,933	$3,373	$5,446	$4,062
Expenses						
Transportation and selling	-	-	77	136	77	136
Operating	368	274	87	20	455	294
Purchased product	1,059	265	3,780	3,183	4,839	3,448
Depreciation, depletion and amortization	56	38	10	19	66	57
Segment Income	$ 30	$ 112	$ (21)	$ 15	$ 9	$ 127

(*) Includes transportation cost optimization 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.

Capital Expenditures

	Three Months Ended December 31		Year Ended December 31	
(C$ millions)	2003	2002	2003	2002
Upstream				
Canada	$ 1,199	$ 769	$ 4,449	$ 2,175
United States	454	331	1,339	1,831
Ecuador	123	97	370	265
United Kingdom	238	27	302	130
Other Countries	20	118	109	184
	2,034	1,342	6,569	4,585
Midstream & Marketing	91	34	381	73
Corporate	95	37	150	66
Total	$ 2,220	$ 1,413	$ 7,100	$ 4,724

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
	As at		As at	
(C$ millions)	December 31, 2003	December 31, 2002	December 31, 2003	December 31, 2002
Upstream	$ 23,950	$ 21,570	$ 28,097	$ 25,340
Midstream & Marketing	1,014	742	2,428	2,216
Corporate	295	192	632	492
Assets of Discontinued Operations			-	3,404
Total	$ 25,259	$ 22,504	$ 31,157	$ 31,452

5. 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. 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 net cash consideration of $427 million. This transaction completed 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 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 by the purchaser, and recorded an after-tax gain on sale of $263 million.

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.

The following tables present the effect of the discontinued operations on the Consolidated Financial Statements:

Consolidated Statement of Earnings	For the three months ended December 31							
	Syncrude		Merchant Energy		Midstream-Pipelines		Total	
(C$ millions)	2003	2002	2003	2002	2003	2002	2003	2002
Revenues, Net of Royalties	$ -	$ 134	$ -	$ (9)	$ -	$ 63	$ -	$ 188
Expenses								
Transportation and selling	-	1	-	-	-	-	-	1
Operating	-	52	-	-	-	25	-	77
Purchased product	-	-	-	(10)	-	-	-	(10)
Depreciation, depletion and amortization	-	9	-	(1)	-	4	-	12
Administrative	-	-	-	1	-	-	-	1
Interest, net	-	2	-	-	-	8	-	10
Loss on discontinuance	-	-	-	6	-	-	-	6
	-	64	-	(4)	-	37	-	97
Net Earnings (Loss) Before Income Tax	-	70	-	(5)	-	26	-	91
Income tax expense (recovery)	-	27	-	(2)	-	10	-	35
Net Earnings (Loss) from Discontinued Operations	$ -	$ 43	$ -	$ (3)	$ -	$ 16	$ -	$ 56

Consolidated Statement of Earnings

(C$ millions)	Syncrude(*) 2003	Syncrude(*) 2002	Merchant Energy 2003	Merchant Energy 2002	Midstream-Pipelines(*) 2003	Midstream-Pipelines(*) 2002	Total 2003	Total 2002
	For the year ended December 31							
Revenues, Net of Royalties	$ 129	$ 365	$ -	$1,454	$ -	$ 212	$ 129	$2,031
Expenses								
Transportation and selling	2	4	-	-	-	-	2	4
Operating	69	164	-	-	-	78	69	242
Purchased product	-	-	-	1,465	-	-	-	1,465
Depreciation, depletion and amortization	10	26	-	-	-	27	10	53
Administrative	-	-	-	35	-	-	-	35
Interest, net	-	2	-	-	-	30	-	32
Foreign exchange (gain)	-	-	-	-	-	(3)	-	(3)
(Gain) loss on discontinuance	-	-	-	30	(343)	-	(343)	30
	81	196	-	1,530	(343)	132	(262)	1,858
Net Earnings (Loss) Before Income Tax	48	169	-	(76)	343	80	391	173
Income tax expense (recovery)	13	45	-	(27)	80	32	93	50
Net Earnings (Loss) from Discontinued Operations	$ 35	$ 124	$ -	$ (49)	$ 263	$ 48	$ 298	$ 123

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

Consolidated Balance Sheet

(C$ millions)	Syncrude 2003	Syncrude 2002	Merchant Energy 2003	Merchant Energy 2002	Midstream-Pipelines 2003	Midstream-Pipelines 2002	Total 2003	Total 2002
	As at December 31							
Assets								
Cash and cash equivalents	$ -	$ 29	$ -	$ -	$ -	$ 68	$ -	$ 97
Accounts receivable and accrued revenues	-	65	-	-	-	31	-	96

Inventories	-	15	-	-	-	1	-	16
	-	109	-	-	-	100	-	209
Property, plant and equipment, net	-	1,396	-	-	-	817	-	2,213
Investments and other assets	-	-	-	-	-	374	-	374
Goodwill	-	417	-	-	-	191	-	608
	-	1,922	-	-	-	1,482	-	3,404
Liabilities								
Accounts payable and accrued liabilities	-	108	-	5	-	40	-	153
Income tax payable	-	(6)	-	-	-	17	-	11
Short-term debt	-	438	-	-	-	-	-	438
Current portion of long-term debt	-	-	-	-	-	23	-	23
	-	540	-	5	-	80	-	625
Long-term debt	-	-	-	-	-	576	-	576
Future income taxes	-	373	-	-	-	164	-	537
	-	913	-	5	-	820	-	1,738
Net Assets of Discontinued Operations	$ -	$1,009	$ -	$ (5)	$ -	$ 662	$ -	$1,666

6. FOREIGN EXCHANGE (GAIN) LOSS

	Three Months Ended December 31		Year Ended December 31	
(C$ millions)	2003	2002	2003	2002
Unrealized Foreign Exchange (Gain) on Translation of U.S. Dollar Debt Issued in Canada	$ (159)	$ (13)	$ (704)	$ (37)
Other Foreign Exchange (Gain) Loss	(32)	17	(81)	14
	$ (191)	$ 4	$ (785)	$ (23)

7. INCOME TAXES

	Three Months Ended December 31		Year Ended December 31	
(C$ millions)	2003	2002	2003	2002
Provision for Income Taxes				
Current				
Canada	$ (155)	$ (169)	$ (180)	$ (40)
United States	38	-	52	(49)

Ecuador	24	13	54	27
United Kingdom	(4)	(12)	1	-
Other Countries	1	1	2	3
	(96)	(167)	(71)	(59)
Future	228	384	1,217	665
Future tax rate reductions (*)	4	(5)	(482)	(33)
	$ 136	$ 212	$ 664	$ 573

(*) During the second quarter of 2003, both the Canadian federal and Alberta governments substantively enacted income tax rate reductions previously announced. The reduced rates were passed into law during the fourth quarter of 2003.

8. LONG-TERM DEBT

(C$ millions)	As at December 31, 2003	As at December 31, 2002
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	$ 1,842	$ 1,388
Unsecured notes and debentures	1,725	1,825
Preferred securities	326	326
	3,893	3,539
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	539	696
Unsecured notes and debentures	3,505	3,608
Preferred securities	194	237
	4,238	4,541
Increase in Value of Debt Acquired (*)	107	110
Current Portion of Long-Term Debt	(372)	(212)
	$ 7,866	$ 7,978

(*) 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 28 years.

9. ASSET RETIREMENT OBLIGATION

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

	As at December 31,	
(C$ millions)	2003	2002
Asset Retirement Obligation, Beginning of Year	$ 488	$ 259
Liabilities Incurred	89	229
Liabilities Settled	(32)	(21)
Accretion Expense	27	21
Other	(16)	-

Asset Retirement Obligation, End of Year	$ 556	$ 488

The total undiscounted amount of estimated cash flows required to settle the obligation is $4,165 million (2002 - $3,975 million), which has been discounted using a credit-adjusted risk free rate of 5.9 percent. Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at the time of removal.

10. SHARE CAPITAL

	December 31, 2003		December 31, 2002	
(millions)	Number	Amount	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	5.5	161	5.5	139
Shares Repurchased	(23.8)	(437)	-	-
Common Shares Outstanding, End of Year	460.6	$ 8,456	478.9	$ 8,732

During the quarter, the Company purchased, for cancellation, 5,215,000 Common Shares (Year-to-date - 23,839,400 Common Shares) for total consideration of approximately $244 million (Year-to-date - $1,184 million). Of the $1,184 million paid this year, $437 million was charged to share capital, $102 million was charged to paid in surplus and $645 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 after the grant date.

The following tables summarize the information about options to purchase common shares at December 31, 2003:

	Stock Options (millions)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	29.6	39.74
Granted under EnCana Plans	6.4	47.97
Exercised	(5.5)	29.11
Forfeited	(1.7)	41.18
Outstanding, End of Year	28.8	43.13
Exercisable, End of Year	15.6	38.92

	Outstanding Options			Exercisable Options	
	Number of	Weighted Average Remaining	Weighted	Number of Options	Weighted

Range of Exercise Price (C$)	Options Outstanding (millions)	Contractual Life (years)	Average Exercise Price ($)	Out-standing (millions)	Average Exercise Price ($)
13.50 to 19.99	1.5	0.9	18.86	1.5	18.86
20.00 to 24.99	1.3	1.5	22.38	1.3	22.38
25.00 to 29.99	2.2	1.5	26.49	2.2	26.49
30.00 to 43.99	1.3	2.2	38.89	1.2	38.52
44.00 to 53.00	22.5	3.7	47.93	9.4	47.63
	28.8	2.8	43.13	15.6	38.92

As described in Note 2, the Company recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted in 2003 to employees and directors using the fair-value method. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted in prior years, pro forma Net Earnings and Net Earnings per Common Share in 2003 would have been $3,226 million; $6.80 per common share - basic and $6.73 per common share - diluted (2002 - $1,195 million; $2.86 per common share - basic; $2.83 per common share - diluted).

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

	Year Ended December 31	
	2003	2002
Weighted Average Fair Value of Options Granted	$ 12.21	$ 13.31
Risk Free Interest Rate	3.87%	4.29%
Expected Lives (years)	3.00	3.00
Expected Volatility	0.33	0.35
Annual Dividend per Share	$ 0.40	$ 0.40

11. PER SHARE AMOUNTS

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

	Three Months Ended					Year Ended	
	March 31	June 30	September 30	December 31		December 31	
(millions)	2003	2003	2003	2003	2002	2003	2002
Weighted Average Common Shares Outstanding - Basic	479.9	480.6	473.4	462.3	477.9	474.1	417.8
Effect of Dilutive Securities	4.4	3.8	4.5	3.6	4.7	5.6	4.8
Weighted Average Common							

Shares Outstanding - Diluted	484.3	484.4	477.9	465.9	482.6	479.7	422.6

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

(C$ millions)	As at December 31, 2003
Commodity Price Risk	
Natural gas	$ 76
Crude oil	(361)
Gas storage optimization	(32)
Power	5
Foreign Currency Risk	9
Interest Rate Risk	57
	$ (246)

Information with respect to power, 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. No significant new contracts have been entered into as at December 31, 2003.

Natural Gas

At December 31, 2003, the Company's gas risk management activities had an unrecognized gain of $76 million. The contracts were as follows:

	Notional Volumes (MMcf/d)	Physical/ Financial	Term	Price		Unrecognized Gain/ (Loss) (C$ millions)
Fixed Price Contracts						
Sales Contracts						
Fixed AECO price	453	Financial	2004	6.20	C$/mcf	$ 7
NYMEX Fixed price	732	Financial	2004	5.13	US$/mcf	(111)
Chicago Fixed price	40	Financial	2004	5.41	US$/mcf	(1)
AECO Collars	71	Financial	2004	5.34-7.52	C$/mcf	2
NYMEX Collars	50	Physical	2004	2.46-4.90	US$/mcf	(21)
NYMEX Collars	50	Physical	2005	2.46-4.90	US$/mcf	(17)
NYMEX Collars	46	Physical	2006-2007	2.46-4.90	US$/mcf	(26)
Basis Contracts						
Sales Contracts						
Fixed NYMEX to AECO basis	343	Financial	2004	(0.54)	US$/mcf	28
Fixed NYMEX to Rockies basis	255	Financial	2004	(0.48)	US$/mcf	23
Fixed NYMEX to Rockies basis	413	Physical	2004	(0.50)	US$/mcf	34
Fixed NYMEX to San Juan basis	60	Financial	2004	(0.63)	US$/mcf	1
Fixed NYMEX						

to San Juan basis	50	Physical	2004	(0.64)	US$/mcf	1
Fixed Rockies to CIG basis	38	Financial	2004	(0.10)	US$/mcf	-
Fixed NYMEX to AECO basis	877	Financial	2005	(0.66)	US$/mcf	8
Fixed NYMEX to Rockies basis	283	Financial	2005	(0.49)	US$/mcf	21
Fixed NYMEX to Rockies basis	393	Physical	2005	(0.47)	US$/mcf	34
Fixed NYMEX to San Juan basis	75	Financial	2005	(0.63)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	50	Physical	2005	(0.64)	US$/mcf	(1)
Fixed Rockies to CIG basis	50	Financial	2005	(0.10)	US$/mcf	1
Fixed NYMEX to AECO basis	402	Financial	2006-2008	(0.65)	US$/mcf	31
Fixed NYMEX to Rockies basis	175	Financial	2006-2008	(0.57)	US$/mcf	17
Fixed NYMEX to Rockies basis	207	Physical	2006-2007	(0.49)	US$/mcf	29
Fixed NYMEX to San Juan basis	62	Financial	2006	(0.62)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	42	Physical	2006	(0.64)	US$/mcf	(1)
Fixed Rockies to CIG basis	31	Financial	2006-2007	(0.10)	US$/mcf	-
Purchase Contracts						
Fixed NYMEX to AECO basis	47	Financial	2004	(0.80)	US$/mcf	(4)
						53
Gas Marketing Financial Positions(1)						(2)
Gas Marketing Physical Positions(1)						25
						$ 76

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

Crude Oil

As at December 31, 2003, the Company's oil risk management activities had an unrecognized loss of $361 million. The contracts were as follows:

	Notional Volumes (bbl/d)	Term	Average Price (US$/bbl)	Unrecognized Gain/ (Loss) (C$ millions)

Fixed WTI NYMEX Price	62,500	2004	23.13	$ (209)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(148)
3-way Put Spread	10,000	2005	20.00/25.00/28.77	(4)
				(361)
Crude Oil Marketing Financial Positions(1)				(3)
Crude Oil Marketing Physical Positions(1)				3
				$ (361)

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

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 inventories.

As at December 31, 2003, the unrecognized loss on gas storage optimization risk management activities was $32 million, which was as follows:

	Notional Volumes (bcf)	Price (US$/mcf)	Unrecognized Gain/ (Loss) (C$ millions)
Financial Instruments			
Purchases	286.7	5.63	$ 141
Sales	312.4	5.69	(170)
			(29)
Physical Contracts			(3)
			$ (32)

At December 31, 2003, the unrecognized loss on physical contracts of $3 million was more than offset by unrealized gains on physical inventory in storage.

13. RECLASSIFICATION

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

For further information: on EnCana Corporation is available on the company's Web site, www.encana.com, or Investor contact:
EnCana Corporate Development, Sheila McIntosh, Vice-President, Investor Relations, (403) 645-2194; Greg Kist, Manager, Investor Relations, (403) 645-4737; Tracy Weeks, Manager, Investor Relations, (403) 645-2007;

Media contact: Alan Boras, Manager, Media Relations, (403) 645-4747