ENCANA™

first quarter report

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EnCana earns $186 million and generates $765 million of cash flow on a pro forma basis in the first quarter of 2002

Pro forma natural gas sales up 21 percent, exploration success continues, high-quality gas reserves addition in U.S. Rockies

Calgary, Alberta (April 25, 2002) – EnCana Corporation (TSE & NYSE: ECA), created April 5, 2002 by the merger of Alberta Energy Company Ltd. (AEC) and PanCanadian Energy Corporation (PanCanadian), today reported $186 million of earnings and $765 million of cash flow on a pro forma basis during the first quarter of 2002.

All references to earnings, cash flow, production, sales, proceeds of asset sales and other information not specifically contained in the EnCana (formerly PanCanadian) and AEC Management's Discussion and Analysis and interim unaudited consolidated financial statements that are included in this first quarter report are presented on a pro forma basis as if the merger of PanCanadian and AEC had occurred effective January 1, 2002.

STRONG PRO FORMA OPERATING RESULTS

Oil and gas sales increased by 12 percent to 700,846 barrels of oil equivalent per day in the first quarter of 2002, compared to the first quarter of 2001. Natural gas sales averaged 2.7 billion cubic feet per day, up 21 percent over the same period in 2001. Oil and natural gas liquids sales averaged 246,846 barrels per day, down approximately one percent. Operating and general and administrative costs averaged $4.61 per barrel of oil equivalent in the quarter.

"These strong operating results are a testament to the employees of EnCana who, throughout the demanding merger process, remained focused on their jobs, enabling the Company to grow production and maintain cost control," said Gwyn Morgan, EnCana's President and Chief Executive Officer. "In the quarter, we were also able to advance a number of important growth initiatives: a significant discovery at our Tahiti prospect in the deepwater Gulf of Mexico, promising appraisal wells at the Buzzard discovery in the U.K. central North Sea, filing of the regulatory applications for development of the Deep Panuke gas field off Nova Scotia, continued development success at the Ladyfern field in northeast British Columbia and Canada's first reported sales of coal bed methane production. Adding to this outstanding internal progress, we made a timely acquisition that will strengthen our position in one of our key growth platforms – the U.S. Rockies. Last week, we announced a proposed acquisition of approximately 500 billion cubic feet of long life, natural gas equivalent reserves in northwest Colorado," Morgan said.

"The EnCana team used every one of the 68 days that it took to complete the merger to get EnCana ready to hit the ground running. The key integration decisions have already been made and our new teams are working together. Our production numbers are on target and we're making progress towards achieving our targeted annual synergies of one-quarter billion dollars in operating and general and administrative expenses and one-quarter billion dollars in capital investment," Morgan said.

PRO FORMA FINANCIAL RESULTS IMPACTED BY PRICE DECLINES

Lower commodity prices, particularly natural gas prices, impacted first quarter financial results. The average industry natural gas price at AECO for the first quarter of 2002 was $3.49 per thousand cubic feet, compared to $11.37 per thousand cubic feet in the same period a year earlier. The average West Texas Intermediate crude oil benchmark price was US$21.64 per barrel, down 25 percent from the same quarter in 2001. Heavy oil differentials improved as a result of lower industry heavy oil production levels and an improved Gulf Coast heavy oil market. Since the end of 2001, oil and gas prices have strengthened due to indications of an improving North American economy, OPEC restraint and political factors such as tensions in the Middle East.

For the three months ended March 31, 2002, EnCana's pro forma highlights include:

- Net income of $186 million; net income attributable to common shareholders of $175 million, or $0.36 per common share diluted;
- Cash flow of $765 million, or $1.58 per common share diluted;
- Natural gas sales of 2,724 million cubic feet per day, up 21 percent from the first quarter of 2001, with the average realized price declining 64 percent to $3.31 per thousand cubic feet;
- Crude oil and natural gas liquids sales of 246,846 barrels per day, down one percent from the first quarter of 2001, with the average realized price declining 10 percent to $25.37 per barrel;
- Capital investment, net of proceeds on asset sales, of $1,306 million; and
- A strong financial position with debt-to-capitalization of 39 percent (preferred securities included as debt).

"During the first quarter, every one of our six growth platforms, from Western Canada to the U.K. North Sea, either achieved strong production growth or completed important objectives towards the development of long-term, high-impact growth initiatives. By 2005, EnCana is targeting production growth of about 55 percent to more than 1.1 million barrels of oil equivalent per day," Morgan said. "EnCana possesses the scope, scale and reach, plus the financial strength, to deliver enhanced value for shareholders, and our teams are focused on doing just that."

Important Notice: Readers are cautioned that 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.

EnCana Pro Forma

Financial Highlights

As at and for the Three Months Ending March 31, 2002 *($ millions, except per share amounts)*	**EnCana Pro Forma**
Revenues, net of royalties and production taxes	**2,080**
Cash flow from operations	**765**
Per share – diluted	**1.58**
Net earnings	**186**
Per share – diluted	**0.36**
Capital investment, excluding dispositions	**1,345**
Total assets	**28,946**
Long-term debt, including current portion	**7,704**
Preferred securities	**586**
Shareholders' equity	**13,033**
Debt-to-capitalization ratio (adjusted for working capital and including preferred securities as debt)	**39%**
Common Shares	
Outstanding March 31, 2002 *(millions)*	**474.1**
Weighted average diluted *(millions)*	**483.5**

Operating Highlights

	Three Months Ended March 31	
	2002	2001
Sales		
Total barrels of oil equivalent per day	**700,846**	624,124
Natural gas *(million cubic feet per day)*	**2,724**	2,250
Total liquids *(barrels per day)*	**246,846**	249,124
North America		
Conventional oil and NGLs	**163,635**	154,211
Syncrude	**31,548**	32,319
International	**51,663**	62,594
Prices		
North American gas price *($ per thousand cubic feet)*	**3.31**	9.07
North American conventional oil price *($ per barrel)*		
Light/medium	**26.48**	29.71
Heavy	**21.63**	15.61
Syncrude *($ per barrel)*	**34.86**	43.17
International crude oil *($ per barrel)*		
Ecuador	**22.07**	24.71
U.K.	**30.85**	41.26
Natural gas liquids *($ per barrel)*	**22.45**	40.06
Total liquids *($ per barrel)*	**25.37**	28.17

ENCANA CORPORATE DEVELOPMENTS

EnCana Corporation created in less than 10 weeks

In separate meetings on April 4, 2002, AEC common shareholders and optionholders and PanCanadian common shareholders voted strongly in favour of the merger – 91 percent and 81 percent, respectively, of the votes cast. At the PanCanadian meeting, 84 percent of the PanCanadian common shareholders voting cast votes in favour of the name change to EnCana Corporation. On April 5, the morning after the meetings, the Court of Queen's Bench of Alberta approved the transaction and the historic merger was completed later that day, 68 days after the two companies announced their intention to merge.

EnCana's transition teams have made considerable progress in integrating the two companies. The new organizational structure, staffing decisions and assignments have largely been implemented.

Dividends

PanCanadian common shareholders of record as of March 15, 2002 were paid a quarterly dividend of 10 cents per share on March 29, 2002. Recognizing that AEC's annual dividend of 60 cents per share would normally be payable in June, after the expected completion of the merger, AEC's Board of Directors declared a dividend of 45 cents per share which was paid on March 28, 2002 to AEC common shareholders of record as of March 7, 2002.

The Board of Directors of EnCana has declared a quarterly dividend of 10 cents per share payable on June 28, 2002 to common shareholders of record as of June 14, 2002.

Energy services

As part of EnCana's strategic review of its operations, the Company has decided to exit its Houston-based merchant energy operations which are included in the Company's Midstream and Marketing segment of its business. Various exit alternatives are being evaluated with a view to maximizing the value to EnCana. As a result of this strategic decision, the Houston-based merchant energy operations are being accounted for as discontinued operations in the Company's interim financial statements. The Company will honour all existing contracts and commitments to the Company's customers.

Unrelated to the decision to discontinue its Houston-based merchant energy operations, the Company has also determined, in respect of certain sales and purchases of natural gas in its U.S. marketing subsidiary recorded in 2001, that it is appropriate to treat revenue and expenses in respect of those contracts on a "net" basis, rather than on a gross basis as Revenue and Expenses – Direct. This treatment has no effect on the previously reported net income or cash flow of the Company and its balance sheet remains unchanged.

For further details on both of these developments, see Note 3 of the EnCana interim unaudited consolidated financial statements for the period ended March 31, 2002.

ENCANA OPERATIONAL HIGHLIGHTS

Onshore North America

Strong organic growth in natural gas EnCana's sales of produced natural gas in North America during the first quarter, which includes the impact of 161 million cubic feet per day of gas withdrawals from storage, increased to 2,713 million cubic feet per day, up 21 percent on a pro forma basis over the same period last year. The increase in sales came primarily from the U.S. Rockies and the Ladyfern and Greater Sierra regions of northeast British Columbia. The Onshore North America division drilled more than 1,000 net wells during the first quarter.

High-quality natural gas assets addition in the U.S. Rockies On April 17, EnCana announced that its U.S. subsidiaries had entered into an acquisition agreement, for approximately C$461 million (US$292 million), which expands production, reserves and landholdings in the U.S. Rockies. The Company has agreed to purchase approximately 500 billion cubic feet of long-life natural gas and associated natural gas liquids reserves and about 180,000 net acres of undeveloped land in the Piceance Basin of northwest Colorado. The acquisition also includes a gathering system and a gas plant. These properties are currently producing an average of 38 million cubic feet of gas equivalent per day. EnCana plans to drill about 50 wells on the acquired lands and increase daily production to about 55 million cubic feet of gas equivalent by the end of 2002. EnCana has achieved great success applying its tight gas development expertise to multi-zone formations of this nature and expects to triple production from these properties in the next three years. The transaction is subject to regulatory approvals and certain other conditions, and is expected to close at the end of May 2002.

Greater Sierra production rising In the Greater Sierra area of northeast British Columbia, EnCana drilled 45 wells during its winter program. The Company expects daily production to average about 150 million cubic feet of gas this year. EnCana has clearly identified substantial growth from its extensive lands in the region and is forecasting production to more than double by 2005.

Ladyfern gas development At the Ladyfern gas field, located in northeast British Columbia, the Company successfully drilled seven wells, including six development wells and one step-out well. Current production from this area is approximately 140 million cubic feet per day. Results of two additional exploration wells are under evaluation.

EnCana's coal bed methane pilot projects both showing promise In January 2002, the EnCana and MGV Energy Inc. joint venture, operating on the Palliser Block in southern Alberta, initiated the first significant coal bed methane gas sales reported in Canada. Six wells are producing at stable flow rates ranging from 30,000 to 250,000 cubic feet of natural gas per day per well. Long-term production tests are in progress to verify reserve estimates and stabilize production rates. Initial test results to date indicate that net recoverable reserves on the joint venture lands within the Palliser Block could be approximately one to two billion cubic feet of natural gas per section, with upside from a completion-optimization program now underway. The Company anticipates being in a position to make decisions regarding commercial development by mid-2002.

In southeastern British Columbia, EnCana continued testing and evaluating the coal bed methane potential in the Elk Valley. The first pilot project has had 10 wells on test, dewatering coals since late 2001, with encouraging results to date. A decision on advancing to an extended pilot project or commercial scale project is expected before year-end.

Oil and natural gas liquids production and sales rise EnCana's sales of oil and natural gas liquids, which include conventional crude oil, Syncrude production and natural gas liquids, averaged 195,183 barrels per day from the Onshore North America division. On a comparative basis, the average daily sales volume of liquids was up five percent from the first quarter of 2001.

SAGD production ramping up First quarter daily production from the Foster Creek steam-assisted gravity drainage oil project averaged 11,100 barrels and is currently about 15,000 barrels per day. Production is expected to reach 20,000 barrels per day in the second quarter of 2002. EnCana's Christina Lake Phase 1 project is currently being commissioned. Steam injection will begin at Christina Lake in May 2002, with first production expected in the third quarter of 2002.

Weyburn production exceeds expectations First quarter production averaged 13,200 barrels per day, up 22 percent from the first quarter of 2001. Incremental production from this Saskatchewan enhanced oil recovery project now amounts to approximately 2,900 barrels per day of the Weyburn Unit oil production. In early February, the first of two gas recycle compressors started re-injecting produced CO_2 gas into the reservoir.

Syncrude cost performance improves EnCana's share of Syncrude production for the first quarter of 2002 averaged 31,548 barrels per day, down two percent from the same period last year due primarily to unplanned maintenance. Unit operating costs were down by $2.75 per barrel, or 13 percent, to average $17.73 per barrel in the first quarter of 2002. This was due largely to a reduction in natural gas prices in the past year.

Offshore and International Operations

Ecuador Oil production from Ecuador averaged 50,351 barrels per day in the first quarter of 2002, down seven percent due primarily to a reduction of the effective allowable on the SOTE pipeline in the quarter. Daily crude oil sales averaged 38,774 barrels, down from 51,512 barrels in the first quarter of 2001, due to the scheduling of tanker shipments leaving port. The first quarter production that remained in inventory at quarter-end will be sold during the second quarter. Ecuador volumes are constrained by available pipeline transportation. EnCana plans to double its Ecuador production to 100,000 barrels per day in mid-2003, following completion of the OCP Pipeline, which is one-third complete.

East Coast of Canada – development of Deep Panuke advanced In March 2002, regulatory applications were filed with the Canada-Nova Scotia Offshore Petroleum Board and the National Energy Board for development of the Company's $1.1 billion Deep Panuke natural gas project off the coast of Nova Scotia. Regulatory hearings for the project are expected to begin in the fall of 2002, with a decision in the first quarter of 2003. EnCana will decide whether to proceed with construction of Deep Panuke facilities once regulatory approval is received. The project involves the production and processing of raw gas offshore, the transport of market-ready gas via sub-sea pipeline to Goldboro, Nova Scotia, and an interconnection with the Maritimes and Northeast Pipeline main transmission pipeline. Based on current assumptions, commercial production could begin in 2005. The project is estimated to recover reserves of natural gas approaching one trillion cubic feet over an expected 11-year production life of the field.

Offshore and New Ventures Exploration

Gulf of Mexico – promising discovery In early April 2002, EnCana and its partners announced a significant discovery at the Tahiti prospect located in Green Canyon Block 640, approximately 190 miles southwest of New Orleans in the deepwater Gulf of Mexico. The Tahiti No. 1 well is situated in approximately 4,000 feet of water and was drilled to a measured depth of 28,411 feet. Results from the exploratory well indicate the presence of high-quality reservoir sand with total net pay of more than 400 feet. EnCana has a 25 percent working interest with ChevronTexaco as the operator. Tahiti No. 1 is the second well in EnCana's four-well commitment to earn a 25 percent interest in 71 ChevronTexaco-operated blocks in the prolific Mississippi Fanfold Belt in the Gulf of Mexico. Completion of the four-well program is expected by early 2003.

U.K. North Sea – positive results from appraisal wells In April 2002, EnCana reported the results of two appraisal wells, which verified the anticipated extensions of the Buzzard oil discovery, located in the U.K. central North Sea. Additional appraisal drilling is underway on Buzzard. Results from these two wells are expected in May.

Scotian Shelf deep water exploration In the first quarter of 2002, the Company participated in the drilling of the Annapolis B-24 deepwater exploratory well, located 350 kilometres south of Halifax, Nova Scotia in 1,740 metres of water. Drilling of the well was suspended in late March due to a gas influx that occurred at an intermediate well depth of 3,500 metres. Following a detailed analysis of the event and the condition of the well bore, the participants plugged and abandoned the well for mechanical reasons. The participants have started to redrill the Annapolis prospect from a location that is about 500 metres northeast of the original wellbore.

Midstream and Marketing

Express pipeline system During the first quarter, Express pipeline shipments increased two percent over the first quarter of 2001, averaging 155,600 barrels of oil per day to U.S. Rocky Mountain and Midwest markets. EnCana continues to evaluate expansion opportunities, which will be linked to market demand for shipping Canadian crude oil to the U.S.

Financial strength

On a pro forma basis, EnCana possesses a strong financial position. The Company's debt-to-capitalization ratio was 39:61 (preferred securities included as debt). Total first quarter capital investment was $1,345 million, excluding dispositions. Dispositions were $39 million, bringing net capital investment to $1,306 million. EnCana recently received its first long-term debt rating, following the merger, in Canada by Dominion Bond Rating Service. The rating of A(low) confirms EnCana's position as a strong investment grade issuer in the Canadian market.

IMPORTANT NOTICE

This first quarter report includes three appendices, which are also available on the EnCana Web site: www.encana.com.

These are:

- Appendix 1
  EnCana Corporation
  Pro Forma Consolidated Financial Statements, Q1, 2002
- Appendix 2
  EnCana Corporation (formerly PanCanadian Energy Corporation)
  Management's Discussion and Analysis, Q1, 2002 and
  Interim Unaudited Consolidated Financial Statements
- Appendix 3
  Alberta Energy Company Ltd.
  Management's Discussion and Analysis, Q1, 2002 and
  Interim Unaudited Consolidated Financial Statements

All of these documents are filed on Sedar and posted on www.sedar.com

EnCana Corporation

EnCana is the largest North American-based independent oil and gas company with an enterprise value of approximately C$30 billion. It is North America's largest independent natural gas producer and gas storage operator. Ninety percent of the Company's assets are in four key North American growth platforms: Western Canada, offshore Canada's East Coast, the U.S. Rocky Mountains and the Gulf of Mexico. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. In the U.S., EnCana is one of the largest gas explorers and producers in the Rocky Mountain states and has a strong position in the deepwater Gulf of Mexico. The Company has two key high-potential international growth platforms: Ecuador, where EnCana is the largest private sector oil producer, and the U.K. central North Sea, where EnCana is the operator of a very large oil discovery. The Company also conducts high upside potential new ventures exploration in other parts of the world. EnCana is driven to be the industry's best-of-class benchmark in production cost, per-share growth and value creation for shareholders. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol "ECA."

ADVISORY – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's future plans and operations, certain statements contained in this first quarter report 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 first quarter report include, but are not limited to: EnCana's internal projections, expectations or beliefs concerning future operating results, and various components thereof, future economic performance, the production and growth potential of its various assets, including the assets being acquired under the proposed acquisition of assets in the U.S. Rockies; the anticipated date by which EnCana will have exited its Houston-based merchant energy operations; projected increases in daily production of oil, natural gas and natural gas liquids to 2005; plans to drill additional wells to increase production; potential exploration; the anticipated closing date of the proposed transaction to acquire the assets in the U.S. Rockies that are described in this first quarter report; and the potential success of certain projects such as the coal bed methane projects and the other exploratory wells in the Gulf of Mexico and the North Sea.

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; imprecision of reserve estimates; 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 risk that the businesses of AEC and PanCanadian will not be successfully integrated and that the anticipated synergies will not be realized; costs relating to the merger of AEC and PanCanadian 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 and its indirect wholly owned subsidiary, AEC. 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 herein are made as of the date of this first quarter report, 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 first quarter report are expressly qualified by this cautionary statement.

Further information on EnCana Corporation, formerly PanCanadian Energy Corporation, and Alberta Energy Company Ltd., is available on the Corporation's Web site, www.encana.com, or by contacting:

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Selected Financial and Operating Information

The following table sets out certain unaudited financial and operating information for AEC and PanCanadian, as well as unaudited pro forma financial information for EnCana after giving effect to the Merger and certain other adjustments, as at and for the three months ended March 31, 2002. The following information should be read in conjunction with the unaudited Pro Forma Consolidated Financial Statements of EnCana as at and for the periods ended March 31, 2002 and December 31, 2001.

Financial Information *($ millions, except per share amounts)*	AEC	PanCanadian	EnCana Pro Forma
Revenues, net of royalties and production taxes	$ 1,226	$ 1,062	$ 2,080
Net earnings	72	133	186
Per share – diluted	0.37	0.51	0.36
Cash flow	406	389	765
Per share – diluted	2.58	1.48	1.58
Common shares			
Outstanding March 31, 2002	148.3	255.7	474.1
Weighted average diluted	157.5	261.1	483.5
Total assets	14,700	9,920	28,946
Long-term debt, including current portion	4,895	2,288	7,704
Preferred securities	855	126	586
Shareholders' equity	5,948	4,105	13,033
Capital expenditures, excluding acquisitions and dispositions			
Upstream	852	478	1,330
Midstream	11	4	15
Total	863	482	1,345
Debt-to-capitalization (adjusted for working capital and including preferred securities as debt)	52%	37%	39%

Operating Information	AEC	PanCanadian	EnCana Pro Forma	2001 Pro Forma
Sales Volumes				
Natural Gas *(Mmcf/d)*				
North America				
Western Canada	1,346	1,002	2,348	2,012
U.S. Rockies	293	72	365	230
	1,639	1,074	2,713	2,242
International – U.K.	–	11	11	8
Total produced gas sales	1,639	1,085	2,724	2,250
Oil and Natural Gas Liquids *(bbls/d)*				
North America				
Conventional				
Light and medium oil	4,339	68,216	72,555	73,395
Heavy oil	46,765	22,081	68,846	62,368
Natural gas liquids	8,559	13,675	22,234	18,448
	59,663	103,972	163,635	154,211
Syncrude	31,548	–	31,548	32,319
	91,211	103,972	195,183	186,530
International				
Ecuador	38,774	–	38,774	51,512
U.K.	–	12,889	12,889	11,012
Other	–	–	–	70
	38,774	12,889	51,663	62,594
Total	129,985	116,861	246,846	249,124
Total BOE/D	403,152	297,694	700,846	624,124
Average Realized Sales Prices				
Natural Gas *(per thousand cubic feet)*	3.23	3.44	3.31	9.07
Oil *(per barrel)*				
North America				
Conventional				
Light/medium	31.09	26.19	26.48	29.71
Heavy	22.05	20.74	21.63	15.61
Syncrude	34.86	–	34.86	43.17
International				
Ecuador	22.07	–	22.07	24.71
U.K.	–	30.85	30.85	41.26
Natural Gas Liquids *(per barrel)*	27.49	19.17	22.45	40.06
Total Liquids *(per barrel)*	25.82	24.85	25.37	28.17
Operating Costs + G&A per BOE (excluding Syncrude)	4.54	4.70	4.61	

EnCana Corporation (formerly PanCanadian Energy Corporation) APPENDIX 1
Pro Forma Consolidated Statement of Earnings

(Unaudited)

($ millions, except per share amounts)	PanCanadian Three Months Ended March 31, 2002	AEC Three Months Ended March 31, 2002	Pro Forma Adjustments Note 3		Pro Forma Adjustments Note 4		EnCana Pro Forma Consolidated
Revenues, Net of Royalties and Production Taxes							
Upstream	$ 532	$ 835	$ (141)	(b)(i)	$ –		$ 1,248
			22	(b)(ii)			
Midstream and Marketing	520	391	(238)	(a)	–		836
			141	(b)(i)			
			22	(b)(ii)			
Other	10	–	(4)	(b)(iv)	–		(4)
			(10)	(b)(v)			
	1,062	1,226	(208)		–		2,080
Expenses							
Transportation and selling	–	79	73	(b)(ii)	–		152
Direct	577	–	(577)	(b)(iii)	–		–
Operating	–	216	165	(b)(iii)	–		381
Cost of product purchased	–	406	(213)	(a)	–		576
			(29)	(b)(ii)			
			412	(b)(iii)			
General and administrative	26	24	–		–		50
Interest, net	32	72	(4)	(b)(iv)	9	(e)	109
Foreign exchange	–	–	(10)	(b)(v)	–		(10)
Depreciation, depletion and amortization	214	315	–		–		529
Earnings Before the Undernoted	213	114	(25)		(9)		293
Income tax expense (recovery)	82	42	(11)	(a)	(4)	(e)	109
Net Earnings from Continuing Operations	131	72	(14)		(5)		184
Net Earnings from Discontinued Operations	2	–	–		–		2
Net Earnings	133	72	(14)		(5)		186
Distributions on Preferred Securities, Net of Tax	–	16	–		(5)	(e)	11
Net Earnings Attributable to Common Shareholders	$ 133	$ 56	$ (14)		$ –		$ 175
Earnings per Common Share							
Continuing operations							
Basic	$ 0.51	$ 0.38					$ 0.37
Diluted	$ 0.51	$ 0.37					$ 0.36
Net earnings							
Basic	$ 0.52	$ 0.38					$ 0.37
Diluted	$ 0.51	$ 0.37					$ 0.36

Pro Forma Consolidated Balance Sheet

(Unaudited)

($ millions)	**PanCanadian** As at March 31, 2002	**AEC** As at March 31, 2002	**Pro Forma Adjustments** Note 3	Note 4	**EnCana Pro Forma Consolidated**
ASSETS					
Current Assets					
Cash and cash equivalents	$ 519	$ 86	$ –	$ –	$ 605
Accounts receivable and accrued revenue, net	443	1,051	–	–	1,494
Risk management assets	97	–	169 (a)	–	266
Inventories	81	368	50 (a)	–	499
	1,140	1,505	219	–	2,864
Capital Assets, net	8,448	12,389	–	1,382 (a)	22,219
Investments and Other Assets	242	806	–	–	1,048
Net Assets of Discontinued Operations	90	–	–	–	90
Goodwill	–	–	–	2,725 (a)	2,725
	$ 9,920	$ 14,700	$ 219	$ 4,107	$ 28,946
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current Liabilities					
Accounts payable and accrued liabilities	$ 473	$ 1,226	$ –	$ 150 (a)	$ 1,849
Income taxes payable	509	32	–	–	541
Risk management liabilities	91	–	159 (a)	–	250
Current portion of other liabilities	33	–	–	–	33
Current portion of long-term debt	193	24	–	–	217
	1,299	1,282	159	150	2,890
Long-Term Debt	2,095	4,290	–	61 (a)	6,895
				449 (e)	
Project Financing Debt	–	581	–	11 (a)	592
Other Liabilities	320	193	–	–	513
Future Income Taxes	2,101	2,406	26 (a)	490 (a)	5,023
	5,815	8,752	185	1,161	15,913
Shareholders' Equity					
Preferred securities	126	855	–	54 (a)	586
				(449) (e)	
Share capital	214	3,074	–	(3,074) (a)	8,682
				8,468 (a)	
Paid in surplus	27	–	–		27
Retained earnings	3,738	1,762	34 (a)	(1,796) (a)	3,738
Foreign currency translation adjustment	–	257	–	(257) (a)	–
	4,105	5,948	34	2,946	13,033
	$ 9,920	$ 14,700	$ 219	$ 4,107	$ 28,946

Pro Forma Consolidated Statement of Cash Flow from Operations

(Unaudited)

($ millions, except per share amounts)	**PanCanadian** Three Months Ended March 31, 2002	**AEC** Three Months Ended March 31, 2002	**Pro Forma Adjustments** Note 3	**Pro Forma Adjustments** Note 4	**EnCana Pro Forma Consolidated**
Operating Activities					
Net earnings from continuing operations	$ 131	$ 72	$ (14)	$ (5) (e)	$ 184
Depreciation, depletion and amortization	214	315		–	529
Future income taxes	42	16	(11) (a)	–	47
Other	–	3	–	–	3
Cash Flow from Continuing Operations	387	406	(25)	(5)	763
Cash Flow from Discontinued Operations	2	–	–	–	2
Cash Flow	389	406	(25)	(5)	765
Net Change in Non-Cash Working Capital from Continuing Operations	(268)	(244)	(60) (a)	150 (a)	(422)
Net Change in Non-Cash Working Capital from Discontinued Operations	53	–	–	–	53
	$ 174	$ 162	$ (85)	$ 145	$ 396
Cash Flow per Common Share from Continuing Operations					
Basic	$ 1.52	$ 2.75			$ 1.61
Diluted	$ 1.48	$ 2.58			$ 1.58
Cash Flow per Common Share					
Basic	$ 1.52	$ 2.75			$ 1.61
Diluted	$ 1.48	$ 2.58			$ 1.58

Notes to Pro Forma Consolidated Financial Statements

March 31, 2002 *(Unaudited)*

1. BASIS OF PRESENTATION

These unaudited Pro Forma Consolidated Financial Statements have been prepared for information purposes and are prepared on a basis consistent with the Pro Forma Consolidated Financial Statements included in the Joint Information Circular concerning the merger of Alberta Energy Company Ltd. (AEC) and PanCanadian Energy Corporation (PanCanadian). All pro forma adjustments related to the preliminary purchase price allocation have been based upon the estimated fair values determined in preparing the December 31, 2001 Pro Forma Consolidated Financial Statements with no update to March 31, 2002. All pro forma adjustments are consistent with the adjustments made to the December 31, 2001 Pro Forma Consolidated Financial Statements, unless no longer applicable.

These unaudited Pro Forma Consolidated Financial Statements have been prepared from:

(a) PanCanadian's unaudited consolidated financial statements for the three months ended March 31, 2002; and

(b) AEC's unaudited consolidated financial statements for the three months ended March 31, 2002.

The unaudited Pro Forma Consolidated Balance Sheet gives effect to the transaction described in Note 4 as if it had occurred on March 31, 2002. The unaudited Pro Forma Consolidated Statements of Earnings and Cash Flow from Operations give effect to the transaction as if it occurred on January 1, 2002.

These unaudited Pro Forma Consolidated Financial Statements may not be indicative of the results that actually would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future.

These unaudited Pro Forma Consolidated Financial Statements should be read in conjunction with the consolidated financial statements of PanCanadian and AEC.

2. PRINCIPLES OF CONSOLIDATION

These unaudited Pro Forma Consolidated Financial Statements have been prepared on the basis that PanCanadian will account for the transaction as a purchase of AEC using the purchase method of accounting. Accordingly, the assets and liabilities of AEC will be recorded at their estimated fair value.

In completing the transaction, PanCanadian will issue 1.472 Common Shares for each issued and outstanding Common Share of AEC.

3. PRO FORMA ACCOUNTING AND PRESENTATION ADJUSTMENTS AND ASSUMPTIONS

PanCanadian and AEC prepare their consolidated financial statements using similar accounting policies and presentation with the exception of the items noted below. The following accounting policy and financial statement presentation adjustments have been made to match PanCanadian and AEC.

(a) *Mark-to-Market Accounting for Midstream and Marketing Activities*

PanCanadian accounts for its Midstream and Marketing activities using mark-to-market accounting. Certain of AEC's activities related to Midstream and Marketing, specifically purchased gas marketing and gas storage optimization activities, have been restated to a mark-to-market basis of accounting.

(b) *Financial Statement Presentation Adjustments*

(i) To be consistent with PanCanadian's presentation, revenues associated with AEC's purchased gas activity have been reclassified from Upstream revenue.

(ii) To be consistent with AEC's presentation, PanCanadian's Transportation and selling expenses have been reclassified from Upstream and Midstream and Marketing revenues.

(iii) To be consistent with AEC's presentation of expenses, PanCanadian's Operating expenses and Cost of product purchased have been reclassified from Direct expenses.

(iv) To be consistent with AEC's presentation, PanCanadian's interest revenue has been reclassified from Other revenue.

(v) To be consistent with AEC's presentation, PanCanadian's net foreign exchange gain has been reclassified from Other revenue.

Notes to Pro Forma Consolidated Financial Statements

March 31, 2002 *(Unaudited)*

4. PRO FORMA ACQUISITION ADJUSTMENTS AND ASSUMPTIONS

(a) The purchase of AEC for aggregate consideration of $8,618 million comprising 218.4 million Common Shares of PanCanadian based on the exchange ratio of 1.472 PanCanadian Common Shares for each AEC Common Share. The estimated fair values are as at December 31, 2001 unless otherwise stated.

Calculation and preliminary allocation of purchase price:

($ millions, except as noted)		
PanCanadian Common Shares issued to AEC shareholders *(millions)*	218.4	
Price of PanCanadian Common Shares *($ per Common Share)*	38.43	
Value of PanCanadian Common Shares issued		$ 8,391
Fair value of AEC Share Options exchanged for Share Options of EnCana Corporation		77
Transaction costs		150
Total Purchase Price		8,618
Plus: Fair value of liabilities assumed by PanCanadian		
Current liabilities		1,441
Long-term debt		4,351
Project financing debt		592
Preferred securities		423
Capital securities		486
Other non-current liabilities		193
Future income taxes		2,922
Total Purchase Price and Liabilities Assumed		$ 19,026
Fair value of assets acquired:		
Current assets		$ 1,724
Capital assets		13,771
Other non-current assets		806
Goodwill		2,725
Total Fair Value of Assets Acquired		$ 19,026

(b) The number of issued and outstanding AEC Common Shares on the date of the transaction has been assumed to be 148.3 million, taking into account Common Shares issued or purchased between December 31, 2001 and March 31, 2002. This assumes that none of the outstanding options to purchase AEC Common Shares at March 31, 2002 are exercised and converted to AEC Common Shares prior to the transaction.

(c) The number of issued and outstanding options to purchase AEC Common Shares on the date of the transaction has been assumed to be 9.0 million, updated to take into account options exercised between December 31, 2001 and March 31, 2002. The fair value of these options has been included in the calculation of the purchase price. The fair value of these options was estimated at December 31, 2001 using the Black-Scholes option pricing model with the same assumptions as disclosed in Note 13 of the Notes to the AEC 2001 Consolidated Financial Statements. The fair value of these options was calculated to be $77 million, adjusted to reflect options exercised to March 31, 2002.

(d) The total purchase price includes the value of the PanCanadian Common Shares to be issued to the AEC shareholders plus the cash costs of completing the transaction. These costs, estimated to be $150 million, include investment advisor fees, legal and accounting fees, printing and mailing costs and other transaction-related costs. These costs have been added to accounts payable on the unaudited Pro Forma Consolidated Balance Sheet.

Notes to Pro Forma Consolidated Financial Statements

March 31, 2002 *(Unaudited)*

4. PRO FORMA ACQUISITION ADJUSTMENTS AND ASSUMPTIONS (continued)

(e) Included in AEC's Preferred Securities are $430 million principal amount of Capital Securities which are convertible, at the option of the holder, into Common Shares of AEC. AEC also has the option to repay both interest and principal through the issuance of Common Shares. As a result, these securities are treated as equity for accounting purposes and distributions in respect of these securities, net of income tax, are charged directly to Retained Earnings. Immediately prior to the closing of the transaction, AEC supplemented the Trust Indenture covering these securities to remove AEC's option to pay interest and principal through the issuance of Common Shares. With the removal of this option, these securities are treated as long-term debt and distributions in respect of these securities are recorded as interest expense in the unaudited Pro Forma Consolidated Statement of Earnings.

(f) Future income tax expense has been adjusted for the impact of the items noted above that affect current year net earnings.

(g) No adjustment has been made to reflect operating synergies that may be realized as a result of the transaction.

(h) The increase in the carrying value of Capital Assets relates to unproved properties and therefore no adjustment has been made to Depreciation, depletion and amortization.

The purchase price allocation is preliminary and may change as a result of several factors, including:
– changes in the fair values of AEC's assets and liabilities at the closing of the transaction;
– actual number of AEC Common Shares and options to acquire AEC Common Shares outstanding at the date of the closing; and
– actual transaction costs incurred.

However, Management does not believe that the final purchase price allocation will differ materially from that presented in the unaudited Pro Forma Consolidated Financial Statements.

5. GOODWILL

The preliminary purchase price allocation includes approximately $2.7 billion of Goodwill. As required under Canadian generally accepted accounting principles, goodwill will not be amortized into income. However, goodwill will be subject to an annual impairment review and should there be an impairment, that amount would be charged to income.

As outlined in Note 4, the allocation of the purchase price presented is preliminary. The Company will finalize the purchase price allocation after closing the transaction. Prior to that time, Management may determine that there are intangible assets acquired in the transaction, separate and apart from goodwill. To the extent that such intangibles, if any, have definite useful lives, the value assigned to them in the purchase equation will be amortized into income over those useful lives. Although the amount allocated to such intangibles, if any, will not be known until after the closing of the transaction, Management does not believe that any such value, or the related amortization expense, would have a material effect on the unaudited Pro Forma Consolidated Financial Statements presented.

Management's Discussion and Analysis

March 31, 2002

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing EnCana Corporation, formerly PanCanadian Energy Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company, certain statements throughout this Interim Management's Discussion and Analysis (the "MD&A") constitute forward-looking statements within the meaning of the United States *Private Securities Litigation Reform Act* of 1995. Forward-looking statements are typically identified by words such as "anticipate," "believe," "expect," "plan," "intend," or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: the Company's operating costs, the Company's seismic and drilling plans, oil and gas prices, per unit netbacks, the Company's oil, liquids and gas sales, the Company's cash flow from operations and net earnings, the Company's production levels, development plans with respect to the Company's Deep Panuke and Buzzard projects, the impact of hedges on the Company's revenue, capital investment levels, the sources of funding for capital investments, the successful integration of the Company's personnel and businesses with those of Alberta Energy Company Ltd. (AEC) and the timing thereof, and future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves 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. Although the Company 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. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: volatility of crude oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in the Company's North American and foreign oil and gas and midstream operations, risks inherent in the Company's marketing operations, imprecision of reserves estimates, the Company's ability to replace and expand oil and gas reserves, the Company's ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, general economic and business conditions, the Company's ability to enter into or renew leases, the timing and costs of well construction, the Company's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, the Company's ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations, political and economic conditions in the countries in which the Company operates, and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission (the "SEC"). Accordingly, the Company cautions that events or circumstances could cause actual results to differ materially from those predicted. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this MD&A, which is as of the date hereof, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

This Management's Discussion and Analysis (MD&A) for EnCana Corporation, formerly PanCanadian Energy Corporation ("PanCanadian" or the "Company"), should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2002 and March 31, 2001 and the audited consolidated financial statements and MD&A for the year ended December 31, 2001.

CONSOLIDATED OVERVIEW

In the three months ended March 31, 2002, net income was $133 million, or 52 cents per common share, down from $463 million, or $1.81 per common share, in the same period of 2001. Cash flow of $389 million, or $1.52 per common share, compared with $738 million, or $2.89 per common share, in the first quarter of 2001. Weaker market prices for natural gas and crude oil were only partially offset by higher natural gas production and a decline in the pricing differential between lighter and heavier crude oils.

The Company's financial position remained strong. Cash flow in the quarter provided a significant portion of the funding for investing activities of $527 million. At March 31, 2002, debt amounted to $2,288 million and represented 36 percent of debt plus equity. Cash on hand was $519 million and net debt to trailing 12-month cash flow was 90 percent.

During the first quarter of 2002, the Company adopted, on a retroactive basis, the amended Canadian standard on accounting for foreign currency translation. The amendment eliminates the deferral and amortization of foreign exchange gains or losses on long-term monetary items. As a result, there was an increase in reported net income of $8 million in the first quarter of 2002 and a decrease of $31 million in the same quarter last year.

Early in April 2002, PanCanadian and AEC combined their two companies – creating EnCana Corporation. The companies satisfied all closing conditions, including receiving approvals on April 4 from shareholders of PanCanadian and shareholders and option holders of AEC and on April 5 from the Court of Queen's Bench of Alberta. PanCanadian shareholders also approved renaming of the Company to EnCana Corporation. The merger of equals was effected through the exchange of 1.472 PanCanadian (EnCana after the name change) shares for each AEC share. EnCana shares started trading on the Toronto and New York stock exchanges on April 8 under the symbol "ECA."

On April 24, 2002, the Company adopted formal plans to dispose of the Houston-based merchant energy operation, which is included in the Marketing and Midstream segment. Exit alternatives are being evaluated to maximize the value of the disposition. Accordingly, these operations have been accounted for as discontinued operations and the financial statements have been restated as described in Note 3 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

	Three Months Ended March 31	
	2002	2001
Average AECO Price *($ per thousand cubic feet)*	**3.49**	11.37
Average NYMEX Price *(US$ per million British thermal units)*	**2.32**	7.09
Average WTI *(US$ per barrel)*	**21.63**	28.67
WTI Bow River Differential *(US$ per barrel)*	**5.22**	11.87
U.S./Canadian dollar exchange *(US$)*	**0.627**	0.654

High natural gas storage levels continued to have a dampening effect on natural gas prices. Evidence that demand is benefiting from a milder and briefer than expected economic recession, coupled with the prospects of limited new supply due to reduced drilling activity in the U.S., was of little benefit to prices. The AECO index price averaged $3.49 per thousand cubic feet in the first quarter of 2002, compared with $3.44 per thousand cubic feet in the fourth quarter of 2001 and $11.37 per thousand cubic feet in the first quarter of 2001.

Averaging US$21.63 per barrel in the first quarter of 2002, the West Texas Intermediate (WTI) crude oil price was up five percent from an average of US$20.53 per barrel in the fourth quarter of 2001. Prospects for stronger than expected demand growth, co-ordinated cutbacks in OPEC production and an uncertain situation in Iraq and the Middle East combined to build support for firmer crude oil prices. However, the WTI price remained below its average of US$28.67 per barrel in the first quarter of 2001.

There was a significant narrowing in the differential between heavier and lighter crude oil prices as the supply/demand balance for heavy oil improved. The WTI-Bow River differential averaged US$5.22 per barrel in the first three months of 2002, compared with US$9.52 per barrel and US$11.87 per barrel in the last and first quarters of 2001, respectively. Market fundamentals for heavy oil are expected to further benefit from the scheduled resumption in the second quarter of operations at the CITGO refinery in Illinois, which was closed for several months after it suffered a fire, and from the approaching start of the summer asphalt season.

RESULTS OF OPERATIONS

Upstream

Financial Results *($ millions)*	2002 Natural gas	2002 Crude oil	2002 Field NGLs & other	2002 Total	2001 Natural gas	2001 Crude oil	2001 Field NGLs & other	2001 Total
Revenues								
Production	**$ 335**	**$ 235**	**$ 30**	**$ 600**	$ 811	$ 249	$ 47	$ 1,107
Royalties and similar payments	**(34)**	**(33)**	**(1)**	**(68)**	(67)	(25)	(2)	(94)
	301	**202**	**29**	**532**	744	224	45	1,013
Expenses								
Direct operating*	**49**	**55**	**–**	**104**	39	64	–	103
Administrative	**–**	**–**	**–**	**22**	–	–	–	20
Depletion, depreciation and amortization	**–**	**–**	**–**	**206**	–	–	–	170
Upstream income	**$ 252**	**$ 147**	**$ 29**	**$ 200**	$ 705	$ 160	$ 45	720
Capital expenditures (excludes net acquisitions/dispositions)				**$ 478**				$ 351

Three Months Ended March 31

* Direct operating expenses for field NGLs are commingled with natural gas expenses.

Revenue Variances for 2002 Compared to 2001 *($ millions)*	Price	Volume	Total
Natural gas	$ (520)	$ 44	$ (476)
Crude oil	(10)	(4)	(14)
Field NGLs and other	(26)	9	(17)
Total production revenue	$ (556)	$ 49	$ (507)

Three Months Ended March 31

In the first quarter of 2002, Upstream production revenues of $600 million were down $507 million, or 46 percent, from the same quarter of 2001.

The Company's realized natural gas price was $3.44 per thousand cubic feet, a decrease of 61 percent from $8.76 per thousand cubic feet in the first three months of 2001. Hedging activities resulted in a gain of $29 million, or 30 cents per thousand cubic feet, versus a cost of $113 million, or $1.22 per thousand cubic feet, in first quarter of 2001. There was a five-percent increase in average daily natural gas production to 1,085 million cubic feet due chiefly to a successful drilling program.

Compared with the first quarter of 2001, a decline in market prices for lighter crude oils was largely offset by a narrowing in the differential between heavier and premium-priced lighter crude oils. The realized price on the Company's mix of crude oil products of $25.55 per barrel in the first quarter of 2002 was down just four percent, while the benchmark WTI crude oil price declined 25 percent. Hedging activities had unfavourable effects of $8 million, or 82 cents per barrel, in the first quarter of 2002 and $11 million, or $1.14 per barrel, in the same quarter of 2001. Production of crude oil was down two percent, averaging 102,000 barrels per day in the first quarter of 2002. The decline reflects the sale of non-core, crude oil producing properties, as well as the Company's focus on growing its natural gas business.

Excluding the impact of commodity and currency hedging, royalties and similar payments were approximately 12 percent of revenues, compared with eight percent in the first quarter of 2001. The higher rate in 2002 reflected an under-accrual of freehold mineral taxes at year-end 2001.

Unit Direct Operating Expenses ($ per unit)	Three Months Ended March 31 2002	2001
Natural gas and field liquids (per thousand cubic feet)*	$ 0.50	$ 0.42
Crude oil (per barrel)	6.60	7.75
Per barrel of oil equivalent**	4.24	4.41

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

Direct operating expenses in the Upstream division amounted to $104 million in the first quarter of 2002, compared with $103 million in the corresponding quarter of 2001. For natural gas and field liquids, unit operating costs on working interest production rose eight cents to 50 cents per thousand cubic feet equivalent as higher processing and maintenance costs more than offset the benefit of lower electricity charges. Costs associated with working interest production of crude oil decreased $1.15 to $6.60 per barrel. The improvement in unit operating expenses for crude oil was due chiefly to lower electricity costs.

Administrative expenses in the Upstream division were $22 million in the first quarter of 2002, up $2 million from the same period last year. On a barrel of oil equivalent basis, administrative expenses were 82 cents, or up six percent.

Depletion, depreciation and amortization charges amounted to $206 million and compared with $170 million in the first quarter last year. On a barrel of oil equivalent basis, depletion, depreciation and amortization expenses were up 17 percent to $7.69 per barrel due to higher levels of capital spending.

Capital expenditures in the Upstream division were $478 million, up $127 million from the first quarter of 2001. The majority, approximately 72 percent, of this investment in 2002 was directed towards natural gas and crude oil exploration and development in the Western Basin. Approximately 28 percent was targeted to high-impact exploration and other activities internationally and offshore the East Coast of Canada. The Company drilled 571 wells in the first quarter of 2002, 92 percent of which were successful.

Marketing and Midstream

Financial Results ($ millions)	Three Months Ended March 31 2002	2001
Revenues		
Marketing*	$ 976	$ 1,644
Midstream	85	115
	1,061	1,759
Direct expenses		
Marketing*	953	1,616
Midstream	61	102
	1,014	1,718
Margin	47	41
Administrative	9	5
Depreciation and amortization	8	5
Marketing and Midstream income	$ 30	$ 31
Capital expenditures (excludes net acquisitions/dispositions)	$ 4	$ 26

* Marketing and Midstream segment results for the first quarter of 2002 include inter-segment sales of $541 million (2001 – $1,115 million), as disclosed in Note 2 to the unaudited financial statements.

Marketing

Marketed Volumes*	Three Months Ended March 31 2002	2001
Natural gas *(million cubic feet per day)*	**1,347**	1,158
Crude oil *(thousand barrels per day)*	**194**	167
Natural gas liquids *(thousand barrels per day)*	**70**	62
Electricity *(thousand megawatt hours)*	**137**	–
Total *(thousand MMBtu per day)***	**2,936**	2,532

* Included in the marketed volume totals are amounts related to PanCanadian production.
** Conversion assumed at: 1 million cubic feet = 1 thousand MMBtu; 1 thousand barrels = 6 thousand MMBtu; 1 thousand megawatt hours = 10 thousand MMBtu.

Marketing revenues were down 41 percent to $976 million from $1,644 million in the first three months of 2001. The Marketing margin declined to $23 million from $28 million. Lower natural gas prices were the main factor underlying the decline. The margin increased to 2.4 from 1.7 percent of revenues even with lower volatility than in the prior year.

Midstream

Midstream Production	Three Months Ended March 31 2002	2001
Natural gas liquids *(thousand barrels per day)*	**34**	25

Midstream Electricity Megawatt Capacity (as at March 31, 2002)	Megawatt Capacity	Ownership (%)	PanCanadian Megawatt Capacity
Kingston	108	25	**27**
Cavalier	85	100	**85**
Balzac	85	50	**43**
			155

Midstream revenues were down $30 million, or 26 percent, to $85 million in the three months ended March 31, 2002. However, the associated margin nearly doubled, increasing to $24 million from $13 million in the same quarter of 2001. Natural gas liquids (NGLs) production improved 36 percent to 34,000 barrels per day. During the first quarter of last year, the Company reduced production of extracted NGLs in order to realize incremental value through the sale of natural gas, which would have otherwise been consumed in the production process. In the first quarter of 2002, product prices declined from the same period last year; however, significantly lower input costs of natural gas more than offset the price decline and the Midstream margin improved substantially.

In the first quarter of 2002, Midstream revenue included approximately $7 million from the two new 106-megawatt electricity generation plants. The Midstream unit commenced operations of the Cavalier plant at 80 percent of capacity in the third quarter of 2001 and the Balzac plant, which is 50 percent owned by PanCanadian, commenced operations in December 2001 at 80 percent of capacity.

Marketing and Midstream administrative expenses were $9 million in the first quarter of 2002, up from $5 million in the corresponding quarter of 2001. The increase principally reflected higher staffing levels that stemmed from an expanded Marketing and Midstream asset and activity base.

Depreciation and amortization expenses in Marketing and Midstream increased to $8 million from $5 million in the first quarter of 2001 largely because of the depreciation charges on the two new electricity generation plants.

Compared with the first quarter of 2001, capital expenditures decreased $22 million to $4 million due mainly to the completion of construction on the two new electricity generation plants.

Corporate

The Company's foreign exchange position contributed revenue of $10 million in the first quarter of 2002, which contrasted with a charge of $24 million in 2001. In the first quarter of 2002, the Company adopted, on a retroactive basis, the amended Canadian standard on accounting for foreign currency translation. This amendment eliminates the deferral and amortization of foreign exchange gains or losses on long-term monetary items. The effect of the change is disclosed in Note 1 to the unaudited consolidated financial statements.

Corporate administrative expenses in the first quarter of 2002 included a one-time benefit of $5 million. The benefit stemmed from an over-accrual in 2001 of charges associated with the reorganization of Canadian Pacific Limited.

Compared to the first quarter last year, interest expense was up $12 million to $32 million, principally reflecting a higher borrowing level.

The provision for income taxes decreased $189 million to $82 million in the first quarter of 2002 because of the lower operating income. The effective tax rate was 38 percent, unchanged from the first quarter of 2001.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

Cash flow from continuing operations of $387 million in the first three months of 2002 decreased from $712 million in the same period of 2001. The decline stemmed chiefly from weaker market prices. In addition, cash from operating activities was adversely affected by changes in non-cash working capital, which used $243 million in the first quarter of 2002 compared with a source of $142 million in 2001. The variance in working capital changes principally reflected the timing of payments for current income taxes.

The Company's net investing activities in the first quarter of 2002 were up $223 million to $527 million, including Upstream capital spending of $478 million and Marketing and Midstream expenditures of $4 million. Acquisition and disposition activities resulted in net proceeds of $3 million in the first quarter of 2002 and $152 million in the same period of 2001 when dispositions included the sale of the Pelican Lake property.

In the first quarter of 2002, $80 million, or US$50 million, of medium-term notes matured and were retired. The consolidated debt position, including the current portion, was $2,288 million at March 31, 2002 compared with $2,370 million at December 31, 2001. Debt to debt plus equity was 36 percent, essentially unchanged from 37 percent at year-end 2001. At the end of the first quarter, interest coverage on a trailing 12-month basis was 24.5 times, cash on hand was $519 million and net debt to trailing 12-month cash flow was 90 percent.

The Company's financial strength and flexibility is supplemented by a $1.1 billion syndicated credit facility, other bank facilities of $550 million and a $300 million commercial paper program. PanCanadian has US$650 million available under its US$1.5 billion shelf prospectus that was established in the fourth quarter of 2001 for a two-year term. During the third quarter of 2001, the Company renewed a $1 billion Canadian medium-term note shelf for a two-year term. At March 31, 2002, no issuances were outstanding and the total authorized amounts were available for use.

Risk management assets and liabilities recorded on the balance sheet result from the application of mark-to-market accounting for the physical and financial derivative positions in the marketing business, representing primarily current year values. These assets and liabilities are managed strictly in accordance with the Company's prescribed risk limits, and all transactions are executed in accordance with the approved processes and controls set out in the risk management and credit policies. There were no new significant credit provisions taken in 2001 or 2002.

OUTLOOK

The outlook that follows excludes the effect of the merger of PanCanadian and AEC completed early in April 2002.

The Company expects to post a solid performance in 2002. Its growing production should benefit from firming energy prices as the North American economy recovers.

As of March 31, 2002, PanCanadian had the following hedges in place:

- approximately 205 million cubic feet per day of natural gas at an average AECO equivalent of $5.97 per thousand cubic feet from April 1, 2002 to October 31, 2002; and
- 10,000 barrels per day of crude oil sold forward for the period April 2002 to June 2002 at an average WTI price of US$23.57.

Consolidated Statement of Income

(Unaudited) ($ millions, except per share amounts)		Three Months Ended March 31 2002	2001
Revenues	*(note 2)*	**$ 1,062**	$ 1,641
Expenses	*(note 2)*		
Direct		**577**	706
Administrative		**26**	25
Interest on long-term debt		**32**	20
Depletion, depreciation and amortization		**214**	175
		849	926
Income from Continuing Operations before Income Taxes		**213**	715
Provision for Income Taxes			
Current		**40**	195
Future		**42**	76
		82	271
Income from Continuing Operations		**131**	444
Discontinued Operations	*(note 3)*	**2**	19
Net Income		**$ 133**	$ 463
Distributions on Preferred Securities, Net of Tax		**–**	(1)
Net Income Attributable to Common Shareholders		**$ 133**	$ 462
Net Income Attributable per Common Share			
Basic			
Income from continuing operations		**$ 0.51**	$ 1.74
Net income		**$ 0.52**	$ 1.81
Diluted			
Income from continuing operations		**$ 0.51**	$ 1.70
Net income		**$ 0.51**	$ 1.77
Weighted Average Number of Shares Outstanding *(millions)*		**255.3**	255.3

Consolidated Statement of Retained Income

(Unaudited) ($ millions)		Three Months Ended March 31 2002	2001
Retained income at beginning of period			
As previously reported		**$ 3,689**	$ 3,721
Prior period adjustment	*(note 1)*	**(59)**	(42)
As restated		**3,630**	3,679
Net income		**133**	463
Dividends on common shares		**(25)**	(26)
Distributions on preferred securities, net of tax		**–**	(1)
Retained income at end of period		**$ 3,738**	$ 4,115

See selected notes to consolidated financial statements.

Consolidated Statement of Cash Flows

(Unaudited) ($ millions)	Three Months Ended March 31 2002	2001
Operating Activities		
Income from continuing operations	**$ 131**	$ 444
Depletion, depreciation and amortization	**214**	175
Future income taxes	**42**	76
Other	**–**	17
Cash flow from continuing operations	**387**	712
Cash flow from discontinued operations	**2**	26
Cash flow	**389**	738
Net change in non-cash working capital from continuing operations	**(268)**	142
Net change in non-cash working capital from discontinued operations	**53**	113
	174	993
Financing Activities		
Repayment of short-term financing	**–**	(250)
Issuance of long-term debt	**–**	94
Repayment of long-term debt	**(80)**	(155)
Issuance of common shares	**18**	24
Dividends on common shares	**(25)**	(26)
Distributions on preferred securities	**–**	(2)
Net change in non-cash working capital	**(2)**	(2)
	(89)	(317)
Investing Activities		
Petroleum and natural gas properties	**(356)**	(249)
Plant, production and other equipment	**(122)**	(102)
Upstream	**(478)**	(351)
Midstream	**(4)**	(26)
	(482)	(377)
Net dispositions	**3**	152
Net change in other assets	**(17)**	(7)
Net change in non-cash working capital	**(31)**	(75)
Discontinued operations	**–**	3
	(527)	(304)
Foreign Exchange Gain (Loss) on Cash held in Foreign Currency	**(2)**	22
Increase (Decrease) in Cash	**(444)**	394
Cash at Beginning of Period	**963**	197
Cash at End of Period	**$ 519**	$ 591
Supplementary Disclosure of Cash Flow Information		
Interest paid	**$ 11**	$ 19
Income taxes paid	**$ 191**	$ 14

See selected notes to consolidated financial statements.

Consolidated Balance Sheet

($ millions)		As at March 31 2002 (Unaudited)	As at December 31 2001 (Audited)
Assets			
Current assets			
Cash		$ 519	$ 963
Accounts receivable		443	518
Risk management assets		97	105
Inventories		81	87
		1,140	1,673
Property, plant and equipment, at cost		15,208	14,738
Less accumulated depletion, depreciation and amortization		(6,760)	(6,576)
		8,448	8,162
Deferred charges and other assets	*(note 1)*	242	237
Net assets of discontinued operations	*(note 3)*	90	142
		$ 9,920	$ 10,214
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities		$ 473	$ 684
Income taxes payable		509	656
Risk management liabilities		91	100
Current portion of deferred credits and liabilities		33	40
Current portion of long-term debt		193	160
		1,299	1,640
Long-term debt		2,095	2,210
Deferred credits and liabilities	*(note 1)*	320	325
Future income taxes		2,101	2,060
Shareholders' equity			
Preferred securities		126	126
Common shares	*(note 4)*	214	196
Paid in surplus		27	27
Retained income	*(note 1)*	3,738	3,630
		4,105	3,979
		$ 9,920	$ 10,214

See selected notes to consolidated financial statements.

Selected Notes to Consolidated Financial Statements

Three Months Ended March 31, 2002 *(Unaudited)*

The interim consolidated financial statements include the accounts of EnCana Corporation (formerly PanCanadian Energy Corporation) and its subsidiaries (the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2001, except as described 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, 2001.

NOTE 1. CHANGES IN ACCOUNTING POLICIES

Foreign Currency Translation

Effective January 1, 2002, the Company retroactively adopted amendments to the Canadian accounting standard for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items, that do not qualify for hedge accounting, are recorded in earnings as they arise. Previously, these exchange gains or losses were deferred and amortized over the remaining life of the monetary item. Prior periods have been restated for the change in accounting policy. The change results in an increase to net income of $8 million for 2002 (2001 – decrease of $31 million). The effect of this change on the December 31, 2001 consolidated balance sheet is an increase in long-term debt and a reduction in deferred credits of $92 million, as well as a reduction in deferred charges and retained income of $59 million.

NOTE 2. SEGMENTED INFORMATION

Statement of Income ($ millions)		Three Months Ended March 31 2002	2001
Upstream			
Revenues			
Gas		**$ 335**	$ 811
Oil – Light/medium		**193**	222
Oil – Heavy		**42**	27
Field liquids		**25**	43
Processing and other income		**5**	4
Royalties and similar payments		**(68)**	(94)
		532	1,013
Expenses			
Direct			
Gas and related products		**47**	37
Oil – Light/medium		**39**	45
Oil – Heavy		**16**	19
Gas processing – royalty interest		**2**	2
		104	103
Administrative		**22**	20
Depletion, depreciation and amortization		**206**	170
		332	293
Upstream Income		**200**	720
Marketing and Midstream			
Revenues			
Marketing		**976**	1,644
Midstream		**85**	115
		1,061	1,759
Expenses			
Direct			
Marketing		**953**	1,616
Midstream		**61**	102
		1,014	1,718
Administrative		**9**	5
Depreciation and amortization		**8**	5
		1,031	1,728
Marketing and Midstream Income		**30**	31
Income Before Corporate Activities		**230**	751
Foreign exchange gain (loss)		**10**	(24)
Interest and other revenues		**–**	8
Interest expense on long-term debt		**(32)**	(20)
Corporate administrative expenses*		**5**	–
Income before income taxes		**213**	715
Provision for income taxes		**82**	271
Income from continuing operations		**131**	444
Discontinued operations	*(note 3)*	**2**	19
Consolidated Net Income		**$ 133**	$ 463

* 2002 corporate administrative expenses include a $5 million recovery for costs associated with the reorganization of CPL.

NOTE 2. SEGMENTED INFORMATION (continued)

Reconciliation of Segment Results to the Consolidated Income Statement

For the Three Months Ended March 31, 2002 *($ millions)*	Upstream	Marketing & Midstream	Corporate	Inter-segment Eliminations*	Consolidated Total
Revenues	**$ 532**	**$ 1,061**	**$ 10**	**$ (541)**	**$ 1,062**
Expenses					
Direct	**104**	**1,014**	**–**	**(541)**	**577**
Administrative	**22**	**9**	**(5)**	**–**	**26**
Interest on long-term debt	**–**	**–**	**32**	**–**	**32**
Depletion, depreciation and amortization	**206**	**8**	**–**	**–**	**214**
Income Before Income Taxes	**$ 200**	**$ 30**	**$ (17)**	**$ –**	**$ 213**

For the three months ended March 31, 2001 *($ millions)*					
Revenues	$ 1,013	$ 1,759	$ (16)	$ (1,115)	$ 1,641
Expenses					
Direct	103	1,718	–	(1,115)	706
Administrative	20	5	–	–	25
Interest on long-term debt	–	–	20	–	20
Depletion, depreciation and amortization	170	5	–	–	175
Income Before Income Taxes	$ 720	$ 31	$ (36)	$ –	$ 715

* Inter-segment eliminations represent the sales of natural gas, crude oil and NGLs from the Upstream segment to the Marketing and Midstream segment.

	Three Months Ended March 31	
Net Additions to Capital Assets *($ millions)*	**2002**	2001
Upstream	**$ 476**	$ 114
Marketing and Midstream	**4**	21
	$ 480	$ 135

NOTE 2. SEGMENTED INFORMATION (continued)

Selected Balance Sheet Disclosure

As at March 31, 2002 *($ millions)*	Upstream	Marketing & Midstream	Corporate & Eliminations	Discontinued Operations	Consolidated Total
Cash*	**$ –**	**$ –**	**$ 519**	**$ –**	**$ 519**
Non-cash current assets	**525**	**449**	**(353)**	**519**	**1,140**
Property, plant and equipment, net	**7,975**	**473**	**–**	**9**	**8,457**
Other assets and deferred charges	**182**	**8**	**52**	**17**	**259**
Total Identifiable Assets	**$ 8,682**	**$ 930**	**$ 218**	**$ 545**	**$ 10,375**
Current Liabilities*	**$ (381)**	**$ (329)**	**$ (396)**	**$ (454)**	**$ (1,560)**

As at December 31, 2001 *($ millions)*	Upstream	Marketing & Midstream	Corporate & Eliminations	Discontinued Operations	Consolidated Total
Cash*	$ –	$ –	$ 963	$ –	$ 963
Non-cash current assets	447	588	(325)	702	1,412
Property, plant and equipment, net	7,687	475	–	9	8,171
Other assets and deferred charges	187	6	44	17	254
Total Identifiable Assets	$ 8,321	$ 1,069	$ 682	$ 728	$ 10,800
Current Liabilities*	$ (489)	$ (456)	$ (535)	$ (584)	$ (2,064)

As at March 31, 2001 *($ millions)*	Upstream	Marketing & Midstream	Corporate & Eliminations	Discontinued Operations	Consolidated Total
Cash*	$ –	$ –	$ 591	$ –	$ 591
Non-cash current assets	808	704	(715)	742	1,539
Property, plant and equipment, net	6,717	356	–	5	7,078
Other assets and deferred charges	194	13	41	27	275
Total Identifiable Assets	$ 7,719	$ 1,073	$ (83)	$ 774	$ 9,483
Current Liabilities*	$ (357)	$ (669)	$ 64	$ (785)	$ (1,747)

* Current liabilities exclude short-term financing and current portion of long-term debt. Cash and income taxes payable have been included in the Corporate and Eliminations balances.

NOTE 3. DISCONTINUED OPERATIONS

On April 24, 2002, the Company adopted formal plans to dispose of the Houston-based merchant energy operation, which is included in the Marketing and Midstream segment. Accordingly, these operations have been accounted for as discontinued operations.

The following tables present the effect of the discontinued operations on the Consolidated Financial Statements as at March 31.

Consolidated Statement of Income *($ millions)*	**2002**	2001
Revenues	**$ 746**	$ 1,522
Expenses		
Direct	**733**	1,483
Administrative	**10**	7
Depletion, depreciation and amortization	**–**	1
	743	1,491
Income before income taxes	**3**	31
Income taxes	**1**	12
Net income from discontinued operations	**$ 2**	$ 19

NOTE 3. DISCONTINUED OPERATIONS *(continued)*

Consolidated Balance Sheet *($ millions)*	**2002**	2001
Accounts receivable	**$ 359**	$ 507
Risk management assets	**138**	227
Inventories	**22**	8
	519	742
Property, plant and equipment, at cost	**13**	8
Less accumulated depletion, depreciation and amortization	**(4)**	(3)
	9	5
Deferred charges and other assets	**17**	27
	545	774
Accounts payable and accrued liabilities	**339**	568
Risk management liabilities	**115**	217
	454	785
Deferred credits and liabilities	**1**	2
	455	787
Net assets of discontinued operations	**$ 90**	$ (13)

For comparative purposes, the following tables present the effect of the discontinued operations on the Consolidated Financial Statements for the years ended December 31.

Consolidated Statement of Income *($ millions)*	2001	2000	1999
Revenues	$ 4,085*	$ 3,025	$ 1,612
Expenses			
Direct	3,983*	2,961	1,623
Administrative	43	26	20
Depletion, depreciation and amortization	4	3	3
	4,030	2,990	1,646
Income before income taxes	55	35	(34)
Income taxes	22	13	(14)
Net income from discontinued operations	$ 33	$ 22	$ (20)

* Upon review of additional information related to 2001 sales and purchases of natural gas by the U.S. marketing subsidiary, the Company has determined certain revenue and expenses should have been reflected in the financial statements on a net basis rather than included on a gross basis as Revenue and Expenses – Direct. The amendment had no effect on net income or cash flow but Revenues and Expenses – Direct have been reduced by $1,126 million.

NOTE 3. DISCONTINUED OPERATIONS (continued)

Consolidated Balance Sheet *($ millions)*	2001	2000
Accounts receivable	$ 323	$ 699
Risk management assets	309	–
Inventories	70	2
	702	701
Property, plant and equipment, at cost	13	5
Less accumulated depletion, depreciation and amortization	(4)	(2)
	9	3
Deferred charges and other assets	17	32
	728	736
Accounts payable and accrued liabilities	306	631
Risk management liabilities	278	–
	584	631
Deferred credits and liabilities	2	3
	586	634
Net assets of discontinued operations	$ 142	$ 102

Consolidated Statement of Cash Flows *($ millions)*	2001	2000	1999
Operating Activities			
Cash flow	$ 47	$ 26	$ (21)
Net change in non-cash working capital	(48)	(2)	(44)
Cash from operating activities – discontinued operations	$ (1)	$ 24	$ (65)

NOTE 4. COMMON SHARES

The Company's authorized share capital consists of an unlimited number of common shares.

Issued and Outstanding	Number of Shares	*($ millions)*
Balance at January 1, 2002	254,939,851	$ 196
Issued under stock option plan	750,036	18
Balance at March 31, 2002	255,689,887	$ 214

The Company has a stock-based compensation plan (PanCanadian plan) that allows certain key employees to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options are 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 plans expire 10 years from the date the options were granted. As a result of the transaction as described in Note 6, all options outstanding under the PanCanadian plan became exercisable after the close of business on April 5, 2002.

As part of the Canadian Pacific Limited (CPL) reorganization in 2001, CPL stock options were replaced with stock options granted by the Company (CPL replacement plan) in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and, as a result of the reorganization, are all fully vested and exercisable.

Continuity of Stock Options	Number of Options	Weighted Average Exercise Price
Outstanding at January 1, 2002	10,511,178	$ 32.31
Granted under PanCanadian plan	31,000	43.69
Exercised	(750,036)	24.26
Cancelled	(71,650)	29.81
Outstanding at March 31, 2002	9,720,492	$ 33.00
Exercisable at March 31, 2002	2,692,150	$ 22.39

NOTE 4. COMMON SHARES (continued)

The Company accounts for its stock-based compensation plans using the intrinsic-value method. Under the intrinsic-value method, compensation costs are not recognized in the financial statements for share options granted to employees and directors when issued at market value.

Effective January 1, 2002, Canadian accounting standards require disclosure of the impact on net income of using the fair-value method for stock options issued on or after January 1, 2002. If the fair-value method had been used, the effect on the Company's 2002 net income and net income per share would have been immaterial based on the number of stock options granted in this period.

NOTE 5. FINANCIAL INSTRUMENTS

Unrecognized gains (losses) on risk management activities:

($ millions)	**March 31, 2002**
Natural gas	**$ 50**
Crude oil	**(4)**
Foreign currency	**(167)**
Interest rates	**47**
Preferred securities	**4**
	$ (70)

Information with respect to crude oil, currency, and interest rate hedge contracts at December 31, 2001 is disclosed in Note 17 to the annual audited consolidated financial statements. No new material hedging contracts have been entered into subsequent to this disclosure.

NOTE 6. SUBSEQUENT EVENT

On January 27, 2002, PanCanadian and Alberta Energy Company Ltd. (AEC) announced plans to combine their companies. The transaction was accomplished through a plan of arrangement (the "Arrangement") under the *Business Corporations Act* (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. After obtaining approvals of the common shareholders of PanCanadian and of the common shareholders and optionholders of AEC, the Court of Queen's Bench of Alberta and appropriate regulatory and other authorities, the transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation (EnCana). On completion of the transaction, former PanCanadian shareholders own approximately 54 percent and former AEC shareholders own approximately 46 percent of EnCana.

NOTE 7. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2002.

NOTE 8. CONSOLIDATED FINANCIAL RATIOS

The following ratios, based on the consolidated financial statements, are provided in connection with the Company's continuous offering of medium-term notes and debt securities and are for the 12-month period then ended.

	March 31	
	2002	2001
Interest coverage on long-term debt:		
Net income excluding carrying charges of preferred securities	**16.3**	25.6
Net income including carrying charges of preferred securities	**15.5**	23.2
Cash flow excluding carrying charges of preferred securities	**26.1**	35.0
Cash flow including carrying charges of preferred securities	**24.7**	31.7

Supplemental Information for the three months ended March 31, 2002 *(Unaudited)*

HIGHLIGHTS

($ millions, except amounts per share)	Three Months Ended March 31 2002	2001
Revenues	**$ 1,062**	$ 1,641
Net income	**133**	463
Per share – basic	**0.52**	1.81
Cash flow	**389**	738
Per share – basic	**1.52**	2.89
Capital expenditures (excludes net acquisitions/dispositions)	**482**	377
Net debt	**1,769**	506
Debt to debt plus equity	**36%**	20%

UPSTREAM

Daily Production (before royalty)	Three Months Ended March 31 2002	2001
Natural gas *(million cubic feet)*	**1,085**	1,029
Crude oil (barrels)	**102,016**	103,588
Field natural gas liquids *(barrels)**	**14,845**	12,418
Total crude oil and field natural gas liquids *(barrels)**	**116,861**	116,006

* Prior period volumes have been restated to reflect a reclassification related to internal consumption. The reclassification has an immaterial effect on prior period financial statements.

Average Realized Sales Prices *($ per unit)*	Three Months Ended March 31 2002	2001
Natural gas *(per thousand cubic feet)**	**$ 3.14**	$ 9.98
Hedging**	**0.30**	(1.22)
	$ 3.44	$ 8.76
Crude oil *(per barrel)*	**$ 26.37**	$ 27.84
Hedging**	**(0.82)**	(1.14)
	$ 25.55	$ 26.70
Field natural gas liquids *(per barrel)**	**$ 19.17**	$ 38.53

* Prior period prices have been restated to reflect a reclassification related to internal consumption. The reclassification has an immaterial effect on prior period financial statements.
** Hedging activity includes the effect of both currency and commodity hedging.

Supplemental Information for the three months ended March 31, 2002 *(Unaudited)*

Netbacks – Western Basin *($ per unit)*	Three Months Ended March 31 **2002**	2001
Crude oil *(per barrel)*		
Revenues	**$ 25.75**	$ 26.58
Royalties and similar payments	**4.00**	2.99
Operating expenses	**6.35**	7.10
Netback before hedging	**15.40**	16.49
Hedging	**(0.89)**	(1.28)
Netback after hedging	**$ 14.51**	$ 15.21
Natural gas *(per thousand cubic feet)*		
Revenues	**$ 3.14**	$ 10.02
Royalties and similar payments	**0.35**	0.73
Operating expenses	**0.47**	0.40
Netback before hedging	**2.32**	8.89
Hedging	**0.30**	(1.23)
Netback after hedging	**$ 2.62**	$ 7.66

Netbacks – United Kingdom *($ per unit)*	Three Months Ended March 31 **2002**	2001
Crude oil *(per barrel)*		
Revenues	**$ 31.15**	$ 41.18
Operating expenses	**2.83**	4.72
Netback before hedging	**28.32**	36.46
Hedging	**(0.30)**	0.08
Netback after hedging	**$ 28.02**	$ 36.54

Management's Discussion and Analysis

March 31, 2002

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing Alberta Energy Company Ltd. ("AEC" or the "Company") shareholders and potential investors with information regarding the Company, certain statements throughout this Management's Discussion and Analysis (the "MD&A") contains certain forward-looking statements within the meaning of the United States *Private Securities Litigation Reform Act* of 1995. Forward-looking statements are typically identified by words such as "anticipate," "believe," "expect," "plan," "intend," or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: the Company's operating costs, the Company's seismic and drilling plans, oil and gas prices, per unit netbacks, the Company's oil, liquids and gas sales, the Company's cash flow from operations and net earnings, the Company's production levels, the Company's share of Syncrude production, development plans with respect to the Company's Foster Creek SAGD commercial project, the timing of the closing of the sale of the Company's Colombian assets, the impact of hedges on the Company's revenue in a low price environment, capital investment levels, the sources of funding for capital investments, the successful integration of the Company's personnel and businesses with those of PanCanadian Energy Corporation ("PanCanadian") and the timing thereof, and future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves 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. Although AEC 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. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: volatility of crude oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in the Company's North American and foreign oil and gas and midstream operations, risks inherent in the Company's marketing operations, imprecision of reserves estimates, the Company's ability to replace and expand oil and gas reserves, the Company's ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, general economic and business conditions, the Company's ability to enter into or renew leases, the timing and costs of well and pipeline construction, the Company's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, the Company's ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations, political and economic conditions in the countries in which the Company operates including Ecuador, and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission (the "SEC"). Accordingly, the Company cautions that events or circumstances could cause actual results to differ materially from those predicted. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this MD&A, which is as of the date hereof, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Management's discussion and analysis of the financial condition and results of operations is to be read in conjunction with the Interim Unaudited Consolidated Financial Statements at and for the three months ended March 31, 2002 and Management's Discussion and Analysis and Audited Consolidated Financial Statements at and for the year ended December 31, 2001.

SUBSEQUENT EVENT

On April 5, 2002, AEC and PanCanadian announced the completed merger of their two companies, creating EnCana Corporation ("EnCana"). The Court of Queen's Bench of Alberta approved the plan of arrangement involving AEC, one day after shareholders and option holders of AEC and shareholders of PanCanadian voted 91% and 81%, respectively, in favor of the transaction. PanCanadian shareholders also approved changing PanCanadian's name to EnCana Corporation. Under the terms of the merger, AEC shareholders received 1.472 PanCanadian (EnCana after the name change) Common Shares for each AEC Common Share they owned.

CONSOLIDATED SUMMARY

Consolidated Net Earnings for the three months ended March 31, 2002 amounted to $72.0 million, a 78% decrease, or $0.37 per share, diluted ("per share") compared to $332.6 million, or $2.03 per share, in 2001 (2000 – $118.8 million; $0.79 per share).

Consolidated Cash Flow from Operations decreased 50% to $405.8 million for the first three months of 2002, or $2.58 per share, from $809.3 million, or $5.13 per share, in 2001 (2000 – $367.2 million; $2.56 per share). Consolidated Revenues, net of royalties and production taxes, totalled $1,226.3 million in the first quarter of 2002, compared to $2,088.8 million in 2001, a 41% decrease (2000 – $1,019.0 million).

Consolidated Financial Summary *($ millions)*	First Quarter **2002**	2001	2000
Net earnings	**72.0**	332.6	118.8
Cash flow from operations	**405.8**	809.3	367.2
Revenues, net of royalties and production taxes	**1,226.3**	2,088.8	1,019.0
Diluted per share *($ per share)*			
Net earnings	**0.37**	2.03	0.79
Cash flow from operations	**2.58**	5.13	2.56

Consolidated Net Revenues decreased primarily as a result of lower natural gas prices and lower Purchased Gas sales in the first quarter of 2002 compared to the same period in 2001. This decrease was partially offset by higher produced natural gas volumes sold. Cash Flow from Operations reflects lower produced gas netbacks, partially offset by lower cash Income Taxes. Net Earnings includes the impact of higher Depreciation, Depletion and Amortization as a result of the higher produced natural gas and crude oil volumes sold and lower future Income Taxes. Interest, net, increased due to higher average long-term debt levels.

Contributions for the past eight quarters are as noted in the following table:

Quarterly Information
($ millions, except per share amounts)

Year Quarter	**2002** **Q1**	2001 Q4	2001 Q3	2001 Q2	2001 Q1	2000 Q4	2000 Q3	2000 Q2
Revenues, net of royalties and production taxes	**1,226.3**	1,206.4	1,339.2	1,637.9	2,088.8	2,067.2	1,364.7	1,072.8
Net earnings	**72.0**	79.8	144.2	267.2	332.6	468.8	222.8	111.6
– per share basic	**0.38**	0.47	0.90	1.70	2.15	3.12	1.51	0.75
– per share diluted	**0.37**	0.46	0.87	1.62	2.03	2.97	1.48	0.73
Cash flow from operations	**405.8**	219.3	436.1	557.9	809.3	924.9	565.6	377.7
– per share basic	**2.75**	1.48	2.96	3.70	5.38	6.32	3.95	2.66
– per share diluted	**2.58**	1.38	2.66	3.32	5.13	6.04	3.75	2.54
Produced gas sales *(MMcf/d)*	**1,639**	1,432	1,395	1,241	1,221	1,301	1,099	917
Oil and NGLs sales *(bbls/d)*	**129,985**	137,125	136,140	135,910	133,118	128,863	120,220	115,922

RESULTS OF OPERATIONS: UPSTREAM

For the three months ended March 31, 2002, Upstream revenues, net of royalties and production taxes and transportation and selling expenses, decreased 49% or $726.9 million, to $756.2 million. This compares to an increase in 2001 of 105% or $761.1 million, to $1,483.1 million. The accompanying table shows the details of these changes by product:

Changes in Oil and Natural Gas Revenues

($ millions)	**2002 Compared to 2001**					2001 Compared to 2000				
Factor:	**Price**	**Price Hedge**	**Volume**	**Royalties & Other**	**Total**	Price	Price Hedge	Volume	Royalties & Other	Total
North America										
Natural gas										
and NGLs	**(922.0)**	**10.6**	**359.8**	**134.7**	**(416.9)**	686.3	10.9	73.3	(191.0)	579.5
Oil										
Conventional	**15.3**	**3.4**	**13.9**	**1.0**	**33.6**	(53.5)	–	21.4	3.3	(28.8)
Syncrude	**(25.9)**	**2.3**	**(3.0)**	**12.1**	**(14.5)**	6.2	–	28.1	(0.2)	34.1
Purchased										
gas sales	**(60.4)**	**29.5**	**(272.8)**	**–**	**(303.7)**	296.6	(108.4)	7.4	–	195.6
International	**(9.4)**	**0.2**	**(28.8)**	**12.6**	**(25.4)**	(62.4)	–	28.2	14.9	(19.3)
Total	**(1,002.4)**	**46.0**	**69.1**	**160.4**	**(726.9)**	873.2	(97.5)	158.4	(173.0)	761.1

In 2002, the $29.5 million Price Hedge represents payments made by financial intermediaries for Purchased gas sales under floating to fixed price swap agreements implemented as a part of the Company's risk management strategy when, at the time of settlement, the market price exceeded the fixed price contract amount. Contemporaneously, similar quantities of gas were forward purchased under fixed price agreements, which, upon settlement, were below market prices in the amount of $1.3 million. For 2002, this strategy resulted in a net benefit of $15.3 million, net of transportation and selling expenses of $15.5 million.

In 2001, the Company made $(108.4) million in Price Hedge payments under floating to fixed price swap agreements. Related fixed price gas purchase agreements were at below market prices in the amount of $161.6 million and resulted in a net benefit of $11.6 million, net of transportation and selling expenses of $41.6 million.

Product Netbacks

The following table summarizes the average net revenue received after deducting transportation, royalties, production taxes and operating costs ("Netback"), by product, for the last eight quarters:

Year Quarter	**2002** **Q1**	2001 Q4	2001 Q3	2001 Q2	2001 Q1	2000 Q4	2000 Q3	2000 Q2
Canada produced gas *($/Mcf)*	**2.00**	1.84	2.02	4.07	6.79	6.27	3.77	2.84
U.S. produced gas *($/Mcf)*	**2.15**	2.23	2.58	4.54	6.20	5.45	4.43	4.60
North America conventional oil *($/bbl)*	**15.79**	16.60	17.27	12.69	10.99	15.23	25.91	23.26
North America NGLs *($/bbl)*	**20.03**	17.12	25.35	28.28	30.04	34.44	28.39	23.55
Syncrude *($/bbl)*	**17.49**	26.02	15.23	18.47	18.93	20.82	21.11	18.91
Ecuador oil *($/bbl)*	**9.24**	13.07	13.63	13.77	12.13	14.05	18.51	15.70

Includes hedge impact where applicable.

North America Results of Operations

The first quarter North America average produced gas price realized, net of transportation and selling expense, was $3.23/Mcf, down 65% from $9.33/Mcf in 2001. A slowing North American economy and warmer than average winter temperatures resulted in lower demand from virtually all sectors and led to above average storage inventories contributing to the decline in natural gas prices. Natural gas liquids prices decreased 36% to $27.49/bbl from $42.96/bbl in 2001.

North America natural gas production increased to 1,478 MMcf/d, up 21% from the 2001 total of 1,222 MMcf/d in the first quarter. An additional 161 MMcf/d was withdrawn from inventory, bringing total produced gas sales to 1,639 MMcf/d in 2002 compared to 1,221 MMcf/d in 2001, up 34%.

Benchmark West Texas Intermediate oil prices ("WTI") averaged US$21.64/bbl in 2002 for the first three months, compared to the 2001 average of US$28.73/bbl. Light-heavy oil price differentials decreased, returning to more traditional levels, averaging $7.25/bbl compared to $17.31/bbl in 2001. During the first quarter of 2002, WTI strengthened from US$19.73/bbl in January to US$24.44/bbl in March in response to improving supply demand fundamentals resulting from OPEC production restraint and an improved economic outlook in North America. Similarly, light-heavy differentials narrowed over the first quarter from $9.05/bbl in January to $5.73/bbl in March. This combination has resulted in significantly improved heavy oil prices.

Total North America liquids sales increased 12% to 91,211 bbls/d in the first three months of 2002 compared to 81,536 bbls/d in 2001, primarily as a result of increased conventional crude production in Canada from the Company's SAGD project at Foster Creek.

During the first quarter of 2002, net capital of $661.6 million was invested in North America upstream activities, of which $532.4 million was directed to Canadian operations and $129.2 million to U.S. operations.

Western Canada

Natural gas prices in Canada averaged $3.20/Mcf, net of transportation and selling expense, in the first three months, down 66% from $9.37/Mcf in 2001 (2000 – $3.00/Mcf). Natural gas production increased 14% to 1,185 MMcf/d from 1,044 MMcf/d in 2001 due to production from the Ladyfern area and increases in the Greater Sierra area in northeast British Columbia (2000 – 930 MMcf/d). Sales of produced natural gas, which includes the impact of gas injections and withdrawals from gas storage, increased to 1,346 MMcf/d, up 29% from 1,043 MMcf/d in the same period of 2001 (2000 – 965 MMcf/d).

Prices for Canadian conventional crude oil averaged $22.81/bbl, net of transportation and selling expense, and including the impact of price hedges, a 22% increase from the $18.75/bbl averaged in the first three months of 2001 (2000 – $32.41/bbl). This increase was principally as a result of the decrease in light-heavy oil price differentials and the benefit from crude oil hedges which offset a decrease in the WTI average price in the quarter. Prices for Syncrude oil, net of transportation and selling expense and including the impact of price hedges, averaged $34.86/bbl compared to $43.17/bbl in 2001, a 19% decrease compared to the 25% decrease in the WTI benchmark price (2000 – $40.97/bbl). Natural gas liquids prices in Canada decreased to $24.05/bbl from $43.11/bbl in 2001 (2000 – $34.11/bbl).

In the first three months of 2002, the Company produced an average of 51,104 bbls/d of conventional oil in Canada, compared to 42,856 bbls/d produced in 2001, an increase of 19% (2000 – 35,372 bbls/d) primarily as a result of increases from the Foster Creek SAGD project. AEC Syncrude sales averaged 31,548 bbls/d, a decrease of 2% from the 32,319 bbls/d sold in 2001 (2000 – 24,497 bbls/d). Natural gas liquids volumes in Canada increased to 5,406 bbls/d year to date, from 4,805 bbls/d in 2001 (2000 – 4,808 bbls/d).

Operating costs in Canada increased to $143.6 million for the first three months of 2002, compared to $135.2 million in 2001 (2000 – $99.7 million). Higher production volumes resulted in the increase, partially offset by lower natural gas fuel costs at Syncrude.

Year-to-date sales of purchased gas decreased to 242 MMcf/d in 2002 from 690 MMcf/d in 2001 (2000 – 878 MMcf/d). Revenue from the sale of purchased gas, net of transportation and selling expense, amounted to $116.1 million, down from $419.8 million in 2001 as a result of lower volumes sold and lower average unit sales prices (2000 – $224.3 million). At March 31, 2002, the Company had contracts in place to purchase 84.8 Bcf of natural gas over an eighteen-month period. Contracts were also in place to deliver 69.2 Bcf during the same time frame.

Capital investment focused on exploration and development activities in the Greater Sierra and Ladyfern areas in northeast British Columbia, and further development at Suffield, Caribou and Pelican Lake.

U.S. Rockies

Year to date, U.S. natural gas prices, net of transportation and selling expense, averaged $3.35/Mcf compared to $9.04/Mcf in 2001 which included $0.73/Mcf related to a mark-to-market adjustment on acquired fixed priced contracts. Natural gas sales increased to 293 MMcf/d from 178 MMcf/d in 2001, reflecting successful ongoing drilling programs, capacity expansion and the addition of production from Mamm Creek. Natural gas liquids volumes increased to 3,153 bbls/d at an average price of $33.38/bbl, up from 1,556 bbls/d at $42.51/bbl in 2001.

Operating costs in the U.S. Rockies increased to $7.8 million for the first three months of 2002, compared to $5.7 million in 2001. Higher production volumes and the addition of Mamm Creek contributed to the increase.

Capital investment in the U.S. Rockies amounted to $129.2 million, year to date, relating to continuing exploration and development of the Jonah and Mamm Creek fields and the acquisition and evaluation of exploratory lands.

<u>Ecuador Results of Operations</u>

Production from Ecuador averaged 50,351 bbls/d in the first quarter of 2002, down 7%, compared to 53,894 bbls/d in 2001 (2000 – 41,703 bbls/d). Sales of crude from Ecuador declined to 38,774 bbls/d from 51,512 bbls/d in 2001 primarily as a result of the timing of tanker shipments leaving port.

Ecuador sales volumes remain constrained by available pipeline transportation which is allocated among shippers based upon the shipper's productive capacity and the quality of crude oil. The completion of the OCP pipeline will remove current transportation constraints.

The Ecuador oil price, net of transportation costs, declined in the first quarter of 2002 to an average of $22.07/bbl, including the impact of allocated price hedges, compared to $24.71/bbl in 2001 as a result of a lower WTI price partially offset by narrower light to heavy differentials and allocated price hedges (2000 – $37.97/bbl). Operating costs in Ecuador increased from $4.53/bbl in the first quarter of 2001 to $5.78/bbl due to lower sales volumes and higher personnel costs.

Capital investments in Ecuador amounted to $132.6 million in the first three months compared to $81.0 million in 2001 and related to continuing exploration and development operations on the Tarapoa Block and Block 15 in preparation for substantially increasing production when the OCP pipeline is completed in 2003.

<u>New Ventures Exploration</u>

Investments in New Ventures Exploration amounted to $22.8 million in the first three months of 2002 compared to $47.3 million in 2001. The Company has ongoing exploration in the Gulf of Mexico, Mackenzie Delta, Alaska, the northwest shelf of Australia and offshore Azerbaijan. During the first quarter, the Company participated in exploration wells in Australia and the Gulf of Mexico, neither of which yielded commercial quantities of crude oil and both of which were abandoned. The Company is assessing further drilling in each of these areas.

During the first quarter of 2002, the Company also entered into exploration commitments in Bahrain, Qatar, and Chad, totalling $140 million over three years.

RESULTS OF OPERATIONS: MIDSTREAM

Midstream revenues decreased 28% to $391.1 million year to date 2002, compared to $542.5 million in 2001 (2000 – $253.3 million), primarily due to the impact of lower natural gas prices on sales related to the gas storage facility optimization program. Operating Cash Flow decreased 52% from $104.1 million year to date 2001 to $49.9 million in 2002, as a result of lower optimization margins realized and to pipeline dispositions in late 2001.

Midstream Capital

Capital investment in Midstream amounted to $10.7 million in the first three months of 2002, primarily related to ongoing improvements to pipelines facilities.

Construction of the 450,000 bbls/d OCP pipeline in Ecuador continues with completion targeted for the second quarter of 2003. To date, $26.5 million has been invested related to the Company's 31.4% equity interest.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated Cash Flow from Operations totalled $405.8 million in the first quarter of 2002 (2001 – $809.3 million), of which $386.3 million, or 95% of the total, originated in the Upstream division (2001 – $746.9 million) and $19.5 million was provided by the Midstream division (2001 – $62.4 million). Produced natural gas and natural gas liquids sales provided $256.8 million or 63% of the consolidated total (2001 – $607.8 million), and crude oil added $117.0 million or 29% (2001 – $137.2 million), including allocated corporate costs.

Consolidated cash capital investment totalled $714.5 million in 2002, year to date, in existing core areas (2001 – $963.5 million). An additional $100.8 million cash was invested in corporate and property acquisitions (2001 – $482.8 million), while non-core property dispositions amounted to $35.7 million (2001 – $24.5 million). Total cash net capital investment of $815.3 million exceeded Cash Flow from Operations by $373.8 million. The Company utilized long-term debt to fund the difference.

On a consolidated basis, long-term debt held by the Company, which excludes project financing debt related to the Express System, was $4,290.6 million at March 31, 2002, up $632.6 million from the December 31, 2001 amount of $3,658.0 million. Total long-term debt, including the project financing debt of $580.5 million, is $4,871.1 million (2001 – $4,242.1 million). The Company's unutilized bank credit facilities total $1.6 billion.

Under its Normal Course Issuer Bid, AEC purchased approximately 431,400 shares, for $24.4 million, at an average price of $56.63 in the first quarter of 2002.

Also in the first quarter, the Company declared and paid a special Common Share dividend of 45 cents per Common Share.

RISK MANAGEMENT

The Company's results are influenced by factors such as product prices, interest and foreign exchange rates, royalties, taxes, operations, and credit risk.

The Company has entered into various commodity pricing agreements as a means of managing price volatility. In the first quarter, the Company sold forward an additional 400 MMcf/d of natural gas at fixed prices, bringing the total volume subject to fixed price contracts to an average of 1 Bcf/d for the period January to September 2002. At March 31, 2002, these contracts had an unrealized mark-to-market loss of $133 million in Canada and US$27 million on the U.S. Rockies contracts.

The Company has entered into various financial instruments to manage price volatility related to its gas storage optimization program, including futures, fixed-for-floating swaps and basis swaps. On a combined basis, these instruments had a net unrealized mark-to-market loss of $23.3 million partially offset by a net unrealized mark-to-market gain of $21.4 million on physical inventory in storage at March 31, 2002.

Foreign exchange contracts in the amount of US$171.2 million have been entered into to limit U.S. to Canadian exchange rate fluctuations on the Company's natural gas purchase and sale agreements. At March 31, 2002, these contracts had an unrealized mark-to-market loss of $25.0 million.

An active program of monitoring and reporting day-to-day operations is designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for timely response to an event.

OUTLOOK

The Outlook that follows excludes the impact of the merger transaction, completed April 5, 2002, between AEC and PanCanadian.

The Company's sales forecast for 2002 remains at between 1.525 and 1.575 Bcf/d for produced natural gas and between 142,000 and 153,000 bbls/d of crude oil. While commodity price volatility is expected to continue throughout 2002, there are positive signs, as a result of an improving North American economy and the anticipated continuing effectiveness of crude oil supply management by the OPEC producers. The Company's program of natural gas and crude oil price hedges is expected to reduce the revenue impact of any downward trend in prices.

The Company continues to expect capital investment in core programs to be approximately $2.1 billion before dispositions.

AEC and PanCanadian announced, on April 5, 2002, that all required approvals for the merger of the two companies had been received. The combined organization now operates under the name EnCana Corporation.

April 22, 2002

Alberta Energy Company Ltd.

Consolidated Statement of Earnings *(Unaudited)*

($ millions, except per share amounts)		Three Months Ended March 31 **2002**	2001	2000
Revenues, net of royalties and production taxes		**$ 1,226.3**	$ 2,088.8	$ 1,019.0
Expenses				
Transportation and selling		**79.0**	63.2	43.7
Operating costs		**216.5**	232.8	154.4
Cost of product purchased		**405.9**	782.1	407.5
General and administrative		**24.2**	16.1	10.3
Interest, net	*(Note 4)*	**71.8**	61.3	35.5
Foreign exchange		**0.2**	85.8	4.9
Depreciation, depletion and amortization		**314.7**	264.3	189.5
Earnings Before the Undernoted		**114.0**	583.2	173.2
Minority interest, AEC Pipelines, L.P.		**–**	–	4.7
Income taxes	*(Note 5)*	**42.0**	250.6	49.7
Net Earnings		**72.0**	332.6	118.8
Preferred securities charges, net of tax		**16.0**	10.3	5.2
Net Earnings Attributable to Common Shareholders		**$ 56.0**	$ 322.3	$ 113.6
Earnings per Common Share				
Basic		**$ 0.38**	$ 2.15	$ 0.81
Diluted		**$ 0.37**	$ 2.03	$ 0.79

Consolidated Statement of Retained Earnings *(Unaudited)*

($ millions)		Three Months Ended March 31 **2002**	2001	2000
Balance, Beginning of Year, as Previously Reported		**$ 1,788.1**	$ 1,264.3	$ 744.7
Retroactive Adjustment for Change in Accounting Policy	*(Note 2)*	**–**	(24.3)	4.3
Balance, Beginning of Year, as Restated		**1,788.1**	1,240.0	749.0
Adjustment for Change in Accounting Policy	*(Note 2)*	**–**	–	(341.3)
Charges for Normal Course Issuer Bid		**(15.5)**	–	(3.7)
Net Earnings		**72.0**	332.6	118.8
		1,844.6	1,572.6	522.8
Common Share Dividends		**(66.5)**	–	–
Preferred Securities Charges, Net of Tax		**(16.0)**	(10.3)	(5.2)
Balance, End of Period		**$ 1,762.1**	$ 1,562.3	$ 517.6

Alberta Energy Company Ltd.

Consolidated Balance Sheet *(Unaudited)*

		As at March 31, 2002			As at December 31,
($ millions)		Upstream	Midstream	**Total**	2001
Assets					
Current Assets					
Cash and cash equivalents		$ 21.4	$ 64.5	**$ 85.9**	$ 104.4
Accounts receivable and accrued revenue, net		638.4	413.2	**1,051.6**	983.5
Inventories		159.4	208.5	**367.9**	320.8
		819.2	686.2	**1,505.4**	1,408.7
Capital Assets		11,100.1	1,289.0	**12,389.1**	11,866.8
Investments and Other Assets		131.3	674.4	**805.7**	822.0
		$12,050.6	$ 2,649.6	**$14,700.2**	$14,097.5
Liabilities and Shareholders' Equity					
Current Liabilities					
Accounts payable and accrued liabilities		$ 877.6	$ 348.0	**$ 1,225.6**	$ 1,042.8
Income taxes payable		24.5	7.7	**32.2**	241.6
Current portion of long-term debt		–	24.4	**24.4**	49.4
		902.1	380.1	**1,282.2**	1,333.8
Long-Term Debt	*(Note 6)*	3,583.7	706.9	**4,290.6**	3,658.0
Project Financing Debt	*(Note 7)*	–	580.5	**580.5**	584.1
Other Liabilities		157.0	35.9	**192.9**	204.5
Future Income Taxes		2,102.2	304.1	**2,406.3**	2,360.5
		6,745.0	2,007.5	**8,752.5**	8,140.9
Shareholders' Equity					
Preferred securities				**854.4**	858.8
Share capital	*(Note 8)*			**3,073.8**	3,052.3
Retained earnings				**1,762.1**	1,788.1
Foreign currency translation adjustment				**257.4**	257.4
		5,305.6	642.1	**5,947.7**	5,956.6
		$12,050.6	$ 2,649.6	**$14,700.2**	$14,097.5

Alberta Energy Company Ltd.

Consolidated Statement of Cash Flows *(Unaudited)*

($ millions, except per share amounts)		Three Months Ended March 31 **2002**	2001	2000
Operating Activities				
Net earnings		**$ 72.0**	$ 332.6	$ 118.8
Depreciation, depletion and amortization		**314.7**	264.3	189.5
Future income taxes		**15.8**	134.5	46.8
Minority interest, AEC Pipelines, L.P.		**–**	–	4.7
Other		**3.3**	77.9	7.4
Cash flow from operations		**405.8**	809.3	367.2
Net change in non-cash working capital		**(244.0)**	317.4	(24.5)
		161.8	1,126.7	342.7
Investing Activities				
Corporate acquisitions	*(Note 3)*	**–**	(435.0)	–
Capital investment		**(815.3)**	(984.8)	(367.5)
Equity investments		**–**	(26.5)	–
Proceeds on disposal of assets		**35.7**	24.5	6.0
Investments and other		**(13.4)**	8.3	(0.6)
Net change in non-cash working capital		**105.8**	240.3	39.2
		(687.2)	(1,173.2)	(322.9)
(Decrease) increase in Cash and Cash Equivalents Before Financing Activities		**(525.4)**	(46.5)	19.8
Financing Activities				
Net issue of long-term debt		**603.4**	29.6	35.5
Issue of Common Shares		**30.4**	20.8	9.1
Purchase of Common Shares	*(Note 8)*	**(24.4)**	–	(7.0)
Common Share dividends		**(66.5)**	–	–
Payments to preferred securities holders		**(10.7)**	(10.3)	(5.2)
AEC Pipelines, L.P. distributions		**–**	–	(6.1)
Net change in non-cash working capital		**(12.3)**	(8.3)	(4.2)
Other		**(13.0)**	32.7	(12.3)
		506.9	64.5	9.8
(Decrease) increase in Cash and Cash Equivalents		**(18.5)**	18.0	29.6
Cash and Cash Equivalents, Beginning of Period		**104.4**	44.6	68.6
Cash and Cash Equivalents, End of Period		**$ 85.9**	$ 62.6	$ 98.2
Cash Flow from Operations per Common Share				
Basic		**$ 2.75**	$ 5.38	$ 2.60
Diluted		**$ 2.58**	$ 5.13	$ 2.56

Alberta Energy Company Ltd.

Notes to Consolidated Financial Statements

1. BASIS OF PRESENTATION

The Company organizes its operations into two business groups. Upstream includes the Company's North America and International exploration for, and production of, natural gas and crude oil. Midstream includes both the Pipelines and Processing operations and the Gas Storage operations.

These interim consolidated financial statements have been prepared on the same basis as the audited consolidated financial statements as at and for the year ended December 31, 2001.

2. CHANGE IN ACCOUNTING POLICY

Effective December 31, 2001, the Company adopted the new Canadian accounting standard for foreign currency translation and, as required by the standard, all prior periods have been restated. The net earnings impact of this change is included in foreign exchange and income taxes on the Consolidated Statement of Earnings.

Effective January 1, 2000, the Company adopted, retroactively without restating prior periods, the liability method of accounting for income taxes as recommended by the Canadian Institute of Chartered Accountants ("CICA"). The Company adopted the recommendations by recording additional capital assets of $273.3 million, a decrease in retained earnings of $341.3 million and an increase in the future income tax liability of $614.6 million.

3. CORPORATE ACQUISITIONS

On February 2, 2001, the Company acquired all of the issued and outstanding shares of Ballard Petroleum, LLC (Ballard) for net cash consideration of approximately $328.4 million. Ballard is engaged in the exploration for, and production of, natural gas and operates a natural gas pipeline in the United States.

In February 2001, the Company acquired a 36% equity interest in Oleoducto Trasandino (Trasandino) for net cash consideration of US$64.3 million. The Trasandino system transports crude oil from Argentina to refineries in Chile.

4. INTEREST, NET

($ millions)	**2002**	2001	2000
Interest expense – long-term debt	**$ 73.5**	$ 63.9	$ 38.0
Interest expense – other	**4.6**	3.0	1.2
Interest income	**(6.3)**	(2.1)	0.8
	71.8	64.8	40.0
Less: Capitalized interest	**–**	3.5	4.5
Interest, net	**$ 71.8**	$ 61.3	$ 35.5

5. INCOME TAXES

The provision for income taxes is as follows:

($ millions)	**2002**	2001	2000
Current			
Canada	**$ 24.9**	$ 104.3	$ 2.4
United States	**–**	7.0	–
Ecuador	**1.3**	4.4	0.5
Other	**–**	0.4	–
	26.2	116.1	2.9
Future	**15.8**	134.5	46.8
Income taxes	**$ 42.0**	$ 250.6	$ 49.7

Alberta Energy Company Ltd.

Notes to Consolidated Financial Statements

6. LONG-TERM DEBT

($ millions)	**March 31, 2002**	December 31, 2001
Upstream		
Canadian Dollar debt	**$ 1,560.1**	$ 1,165.2
U.S. Dollar debt (US$1,269.9)	**2,023.6**	1,907.9
	3,583.7	3,073.1
Midstream		
Canadian Dollar debt	**706.9**	584.9
	$ 4,290.6	$ 3,658.0

7. PROJECT FINANCING DEBT

The Express Pipeline System has outstanding US$132.7 million aggregate principal amount of senior secured notes due 2013 bearing interest at 6.47% and US$246.9 million aggregate principal amount of subordinated secured notes due 2019 bearing interest at 7.39% which are non-recourse to the Company. The notes are secured by the assignment of the accounts receivable of Express Pipeline System and a floating charge over the assets of the Canadian portion of the Express System.

8. SHARE CAPITAL

	March 31, 2002		December 31, 2001	
(millions)	**Number**	**Amount**	Number	Amount
Common Shares outstanding, beginning of period	**147.9**	**$ 3,052.3**	149.9	$ 3,077.4
Shares repurchased	**(0.5)**	**(8.9)**	(3.6)	(73.2)
Employee share option plan	**0.9**	**29.0**	1.5	45.9
Shareholder Investment Plan	**–**	**1.4**	0.1	2.2
Common Shares outstanding, end of period	**148.3**	**$ 3,073.8**	147.9	$ 3,052.3

During the period, the Company has purchased approximately 0.5 million of its Common Shares for total consideration of $24.4 million, resulting in a reduction of share capital of $8.9 million and a charge to retained earnings of $15.5 million.

The following table summarizes the information about options to purchase Common Shares:

	March 31, 2002		December 31, 2001	
	Share Options *(millions)*	**Weighted Average Exercise Price**	Share Options *(millions)*	Weighted Average Exercise Price
Outstanding, beginning of period	**9.9**	**$ 45.60**	8.7	$ 35.21
Granted	**–**	**58.20**	3.1	66.82
Exercised	**(0.9)**	**32.61**	(1.5)	29.88
Forfeited	**–**	**49.48**	(0.4)	44.76
Outstanding, end of period	**9.0**	**46.96**	9.9	45.60

Alberta Energy Company Ltd.

Notes to Consolidated Financial Statements

8. SHARE CAPITAL (continued)

The Company accounts for its stock-based compensation plans using the intrinsic-value method whereby no costs have been recognized in the financial statements for share options granted to employees and directors. As now required by Canadian Generally Accepted Accounting Principles, the impact on compensation costs of using the fair-value method, whereby compensation costs had been recorded in net earnings, must be disclosed. If the fair-value method had been used, the Company's net earnings and net earnings per share would approximate the following pro forma amounts:

($ millions, except per share amounts)	**2002**	2001	2000
Compensation Costs	**7.7**	6.3	5.9
Net Earnings:			
As reported	**72.0**	332.6	118.8
Pro forma	**64.3**	326.3	112.9
Net Earnings per Common Share:			
Basic			
As reported	**0.38**	2.15	0.81
Pro forma	**0.33**	2.10	0.76
Diluted			
As reported	**0.37**	2.03	0.79
Pro forma	**0.32**	1.99	0.75

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:

Risk free interest rate	**3.53%**	3.53%	6.02%
Expected lives *(years)*	**4.00**	4.00	4.00
Expected volatility	**0.32**	0.38	0.41
Dividend per share	**$ 0.60**	$ 0.60	$ 0.40

9. SEGMENTED INFORMATION

(a) Results of Operations

	Western Canada			U.S. Rockies		
($ millions)	**2002**	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 783.1**	$ 1,566.0	$ 741.1	**$ 104.7**	$ 154.8	$ –
Royalties	**90.5**	225.7	79.6	**18.9**	28.4	–
Production Taxes	**–**	–	–	**7.6**	13.2	–
Net Revenues	**692.6**	1,340.3	661.5	**78.2**	113.2	–
Transportation and Selling	**60.2**	44.1	36.5	**6.8**	4.1	–
Operating Costs	**143.6**	135.2	99.7	**7.8**	5.7	–
Cost of Product Purchased	**99.8**	405.1	222.5	**–**	–	–
Operating Cash Flow	**389.0**	755.9	302.8	**63.6**	103.4	–
DD&A	**195.7**	151.0	122.3	**16.6**	9.0	–
DD&A – Acquisitions	**22.7**	21.9	22.7	**24.5**	20.5	–
Segment Income	**$ 170.6**	$ 583.0	$ 157.8	**$ 22.5**	$ 73.9	$ –
Capital Assets – Canada *(including New Ventures)*	**$ 7,179.7**	$ 6,342.1	$ 4,955.2			
– United States *(including New Ventures)*				**$ 1,913.3**	$ 1,569.5	$ 8.4

Notes to Consolidated Financial Statements

9. SEGMENTED INFORMATION (continued)

	North America Total		
($ millions)	**2002**	2001	2000
Gross Revenues	**$ 887.8**	$ 1,720.8	$ 741.1
Royalties	**109.4**	254.1	79.6
Production Taxes	**7.6**	13.2	–
Net Revenues	**770.8**	1,453.5	661.5
Transportation and Selling	**67.0**	48.2	36.5
Operating Costs	**151.4**	140.9	99.7
Cost of Product Purchased	**99.8**	405.1	222.5
Operating Cash Flow	**452.6**	859.3	302.8
DD&A	**212.3**	160.0	122.3
DD&A – Acquisitions	**47.2**	42.4	22.7
Segment Income	**$ 193.1**	$ 656.9	$ 157.8
Capital Assets – Canada *(including New Ventures)*	**$ 7,179.7**	$ 6,342.1	$ 4,955.2
– United States *(including New Ventures)*	**$ 1,913.3**	$ 1,569.5	$ 8.4

	Ecuador – Crude Oil			International New Ventures		
($ millions)	**2002**	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 89.0**	$ 129.5	$ 151.2	**$ –**	$ 0.7	$ 5.2
Royalties	**24.6**	37.3	51.6	**–**	0.1	0.6
Production Taxes	**–**	–	–	**–**	–	–
Net Revenues	**64.4**	92.2	99.6	**–**	0.6	4.6
Transportation and Selling	**12.0**	15.0	7.2	**–**	–	–
Operating Costs	**20.1**	21.0	12.2	**9.9**	9.5	8.9
Cost of Product Purchased	**–**	–	–	**–**	–	–
Operating Cash Flow	**32.3**	56.2	80.2	**(9.9)**	(8.9)	(4.3)
DD&A	**21.9**	25.4	18.6	**0.8**	0.7	1.6
DD&A – Acquisitions	**11.4**	13.5	10.0	**–**	–	–
Segment Income	**$ (1.0)**	$ 17.3	$ 51.6	**$ (10.7)**	$ (9.6)	$ (5.9)
Capital Assets	**$ 1,829.8**	$ 1,476.5	$ 1,124.4	**$ 177.3**	$ 169.1	$ 148.1

Alberta Energy Company Ltd.

Notes to Consolidated Financial Statements

9. SEGMENTED INFORMATION (continued)

($ millions)	International Total 2002	2001	2000	Upstream Total 2002	2001	2000
Gross Revenues	$ 89.0	$ 130.2	$ 156.4	$ 976.8	$ 1,851.0	$ 897.5
Royalties	24.6	37.4	52.2	134.0	291.5	131.8
Production Taxes	–	–	–	7.6	13.2	–
Net Revenues	64.4	92.8	104.2	835.2	1,546.3	765.7
Transportation and Selling	12.0	15.0	7.2	79.0	63.2	43.7
Operating Costs	30.0	30.5	21.1	181.4	171.4	120.8
Cost of Product Purchased	–	–	–	99.8	405.1	222.5
Operating Cash Flow	22.4	47.3	75.9	475.0	906.6	378.7
DD&A	22.7	26.1	20.2	235.0	186.1	142.5
DD&A – Acquisitions	11.4	13.5	10.0	58.6	55.9	32.7
Segment Income	$ (11.7)	$ 7.7	$ 45.7	181.4	664.6	203.5
Less: Corporate Costs						
General and administrative				20.6	11.4	8.3
Corporate DD&A				2.6	2.7	2.6
Interest, net				44.9	32.8	27.8
Foreign exchange				0.4	54.9	3.7
Income taxes				41.5	239.7	46.9
Net Earnings				$ 71.4	$ 323.1	$ 114.2
Capital Assets	$ 2,007.1	$ 1,645.6	$ 1,272.5	$11,100.1	$ 9,557.2	$ 6,236.1

($ millions)	Pipelines and Processing 2002	2001	2000	Gas Storage 2002	2001	2000
Gross Revenues	$ 279.3	$ 286.1	$ 162.8	$ 111.8	$ 256.4	$ 90.5
Royalties	–	–	–	–	–	–
Production Taxes	–	–	–	–	–	–
Net Revenues	279.3	286.1	162.8	111.8	256.4	90.5
Transportation and Selling	–	–	–	–	–	–
Operating Costs	25.2	51.2	27.9	9.9	10.2	5.7
Cost of Product Purchased	216.8	184.7	109.1	89.3	192.3	75.9
Operating Cash Flow	37.3	50.2	25.8	12.6	53.9	8.9
DD&A	12.7	14.8	9.1	3.4	2.7	2.4
DD&A – Acquisitions	1.9	1.9	–	–	–	–
Segment Income	$ 22.7	$ 33.5	$ 16.7	$ 9.2	$ 51.2	$ 6.5
Capital Assets – Canada	$ 335.1	$ 973.2	$ 443.1	$ 139.9	$ 134.3	$ 129.6
– United States	$ 679.1	$ 1,039.1	$ 370.3	$ 134.9	$ 132.5	$ 63.2

Alberta Energy Company Ltd.

Notes to Consolidated Financial Statements

9. SEGMENTED INFORMATION (continued)

($ millions)	Midstream Total 2002	2001	2000	Consolidated Total 2002	2001	2000
Gross Revenues	**$ 391.1**	$ 542.5	$ 253.3	**$ 1,367.9**	$ 2,393.5	$ 1,150.8
Royalties	**–**	–	–	**134.0**	291.5	131.8
Production Taxes	**–**	–	–	**7.6**	13.2	–
Net Revenues	**391.1**	542.5	253.3	**1,226.3**	2,088.8	1,019.0
Transportation and Selling	**–**	–	–	**79.0**	63.2	43.7
Operating Costs	**35.1**	61.4	33.6	**216.5**	232.8	154.4
Cost of Product Purchased	**306.1**	377.0	185.0	**405.9**	782.1	407.5
Operating Cash Flow	**49.9**	104.1	34.7	**524.9**	1,010.7	413.4
DD&A	**16.1**	17.5	11.5	**251.1**	203.6	154.0
DD&A – Acquisitions	**1.9**	1.9	–	**60.5**	57.8	32.7
Segment Income	**31.9**	84.7	23.2	**213.3**	749.3	226.7
Less: Corporate Costs						
General and administrative	**3.6**	4.7	2.0	**24.2**	16.1	10.3
Corporate DD&A	**0.5**	0.2	0.2	**3.1**	2.9	2.8
Interest, net	**26.9**	28.5	7.7	**71.8**	61.3	35.5
Foreign exchange	**(0.2)**	30.9	1.2	**0.2**	85.8	4.9
Minority interest	**–**	–	4.7	**–**	–	4.7
Income taxes	**0.5**	10.9	2.8	**42.0**	250.6	49.7
Net Earnings	**$ 0.6**	$ 9.5	$ 4.6	**$ 72.0**	$ 332.6	$ 118.8
Capital Assets – Canada	**$ 475.0**	$ 1,107.5	$ 572.7			
– United States	**$ 814.0**	$ 1,171.6	$ 433.5			

*(b) Net Capital Investment**

($ millions)	2002	2001	2000
Upstream			
North America			
Conventional	**$ 633.0**	$ 745.6	$ 301.0
Syncrude	**39.6**	15.9	19.5
International	**138.8**	97.3	28.7
Midstream			
Pipelines and Processing	**8.4**	50.2	6.5
Gas Storage	**2.3**	70.5	3.5
Other	**5.6**	7.3	2.3
Total	**$ 827.7**	$ 986.8	$ 361.5

* Excludes corporate acquisitions and corporate dispositions.

Alberta Energy Company Ltd.

Notes to Consolidated Financial Statements

9. SEGMENTED INFORMATION (continued)

(c) Geographic and Product Information

The following tables provide additional product and geographic information for Upstream North America and Midstream not provided in Note (a) Results of Operations:

UPSTREAM NORTH AMERICA

									Natural Gas and NGLs
	Western Canada			United States			Purchased Gas – Canada		
($ millions)	**2002**	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 431.0**	$ 926.0	$ 297.7	**$ 104.7**	$ 154.8	$ –	**$ 141.4**	$ 435.0	$ 242.4
Royalties	**81.3**	203.3	54.1	**18.9**	28.4	–	**–**	–	–
Production Taxes	**–**	–	–	**7.6**	13.2	–	**–**	–	–
Net Revenues	**349.7**	722.7	243.6	**78.2**	113.2	–	**141.4**	435.0	242.4
Transportation and Selling	**28.5**	22.3	13.6	**6.8**	4.1	–	**25.3**	15.2	18.1
Operating Costs	**70.5**	50.5	38.1	**7.8**	5.7	–	**0.2**	6.9	1.9
Cost of Product Purchased	**–**	–	–	**–**	–	–	**99.8**	405.1	222.5
Operating Cash Flow	**$ 250.7**	$ 649.9	$ 191.9	**$ 63.6**	$ 103.4	$ –	**$ 16.1**	$ 7.8	$ (0.1)

						Crude Oil
	Western Canada			Syncrude – Canada		
($ millions)	**2002**	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 110.8**	$ 77.0	$ 108.2	**$ 99.9**	$ 128.0	$ 92.8
Royalties	**9.9**	10.9	14.2	**(0.7)**	11.5	11.3
Net Revenues	**100.9**	66.1	94.0	**100.6**	116.5	81.5
Transportation and Selling	**5.9**	4.7	3.8	**0.5**	1.9	1.0
Operating Costs	**22.5**	19.0	14.4	**50.4**	58.8	45.3
Operating Cash Flow	**$ 72.5**	$ 42.4	$ 75.8	**$ 49.7**	$ 55.8	$ 35.2

MIDSTREAM – PIPELINES AND PROCESSING

	Canada			United States		
($ millions)	**2002**	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 245.4**	$ 238.3	$ 139.8	**$ 33.9**	$ 47.8	$ 23.0
Operating Costs	**10.6**	29.6	18.1	**14.6**	21.6	9.8
Cost of Product Purchased	**204.7**	176.2	99.3	**12.1**	8.5	9.8
Operating Cash Flow	**$ 30.1**	$ 32.5	$ 22.4	**$ 7.2**	$ 17.7	$ 3.4

MIDSTREAM – GAS STORAGE

	Canada			United States		
($ millions)	**2002**	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 47.0**	$ 159.3	$ 71.2	**$ 64.8**	$ 97.1	$ 19.3
Operating Costs	**4.0**	7.8	3.6	**5.9**	2.4	2.1
Cost of Product Purchased	**38.2**	122.0	59.7	**51.1**	70.3	16.2
Operating Cash Flow	**$ 4.8**	$ 29.5	$ 7.9	**$ 7.8**	$ 24.4	$ 1.0

Alberta Energy Company Ltd.

Notes to Consolidated Financial Statements

9. SEGMENTED INFORMATION (continued)

(d) Total Assets

($ millions)	**2002**	2001	2000
Upstream			
North America			
Conventional	**$ 9,036.7**	$ 8,210.9	$ 4,887.0
Syncrude	**777.2**	650.3	584.0
International	**2,236.7**	1,844.9	1,468.5
Midstream			
Pipelines and Processing	**1,951.2**	2,534.2	1,195.0
Gas Storage	**698.4**	318.7	103.5
Total	**$14,700.2**	$13,559.0	$ 8,238.0

10. SUBSEQUENT EVENT

On January 27, 2002, AEC and PanCanadian Energy Corporation ("PanCanadian") announced plans to combine their companies. The transaction was accomplished through a plan of arrangement (the "Arrangement") under the *Business Corporations Act* (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. After obtaining approvals of the common shareholders and optionholders of AEC and of the common shareholders of PanCanadian, the Court of Queen's Bench of Alberta and appropriate regulatory and other authorities, the transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation ("EnCana"). On completion of the transaction, former AEC shareholders own approximately 46% and former PanCanadian shareholders own approximately 54% of EnCana.

Supplemental Financial Information *(Unaudited)*

For the three months ended March 31, 2002

FINANCIAL STATISTICS

(C\$ millions, except per share amounts)	2002 Q1	2001 Year	2001 Q4	2001 Q3	2001 Q2	2001 Q1	2000	1999	1998	1997
Net Earnings[1]	**72.0**	823.8	79.8	144.2	267.2	332.6	922.0	198.5	14.7	195.0
Per share – Basic	**0.38**	5.24	0.47	0.90	1.70	2.15	6.19	1.42	0.13	1.74
– Diluted	**0.37**	4.98	0.46	0.87	1.62	2.03	5.97	1.39	0.13	1.71
Cash Flow from Operations	**405.8**	2,022.6	219.3	436.1	557.9	809.3	2,235.4	946.9	488.5	544.7
Per share – Basic	**2.75**	13.55	1.48	2.96	3.70	5.38	15.53	7.02	4.26	4.87
– Diluted	**2.58**	12.57	1.38	2.66	3.32	5.13	14.89	6.86	4.17	4.79
Shares										
Common shares outstanding *(millions)*	**148.3**	147.9	147.9	147.8	149.8	150.6	149.9	140.8	124.0	112.1
Average	**147.7**	149.3	147.9	148.2	151.0	150.3	143.9	134.8	114.8	111.9
Average Diluted	**157.5**	160.9	150.7	159.8	162.0	161.0	150.2	138.0	117.2	113.7
Price range *(\$ per share)*										
TSE – C\$										
High	**72.76**	78.64	63.70	62.50	78.64	74.39	71.95	48.90	39.00	35.50
Low	**55.69**	50.55	52.86	50.55	59.70	59.00	37.75	30.75	25.75	26.00
Close	**69.51**	60.17	60.17	53.60	62.50	69.90	71.80	45.00	33.00	27.75
NYSE – US\$										
High	**45.83**	50.90	40.65	41.04	50.90	48.25	48.25	32.69	26.25	25.88
Low	**34.60**	32.23	33.62	32.23	39.20	39.19	26.06	20.31	17.38	18.25
Close	**43.90**	37.85	37.85	33.95	41.24	44.31	48.25	31.31	21.50	19.38
Share volume traded *(millions)*	**72.9**	175.6	45.8	49.3	42.2	38.3	156.2	98.1	67.7	81.2
Share value traded *(\$ millions weekly average)*	**357.0**	209.0	199.5	195.2	225.5	198.9	160.1	77.4	42.2	48.1

(1) 1997 net earnings includes a dilution gain on the sale of AEC Pipelines, L.P. of \$178.0 million (\$1.59 per share – basic; \$1.56 per share – diluted).

Supplemental Financial Information *(Unaudited)*

For the three months ended March 31, 2002

FINANCIAL STATISTICS (continued)

Net Capital Investment *($ millions)*	**2002 Q1**	2001	2000	1999	1998	1997
Upstream						
North America						
Conventional	**$ 630.6**	$ 1,769.0	$ 1,202.4	$ 654.0	$ 607.5	$ 667.8
Syncrude	**39.7**	113.8	68.2	103.5	68.3	48.8
New Ventures	**16.6**	56.3	74.2	2.1	0.4	–
Dispositions	**(35.7)**	(121.3)	(72.8)	(40.5)	(25.3)	(92.2)
International						
Ecuador	**69.2**	335.9	215.8	94.7	–	–
New Ventures	**6.2**	140.4	49.5	80.0	64.7	48.3
Dispositions	**–**	(24.2)	(16.4)	(0.9)	–	–
Midstream						
Pipelines and Gas Processing	**8.4**	267.4	62.7	97.9	72.4	157.1
Gas Storage	**2.3**	19.9	12.8	45.6	43.2	40.2
Dispositions	**–**	(172.2)	(2.6)	(66.3)	–	–
Other, net	**5.6**	38.5	16.3	0.5	7.2	11.1
Net Core Capital	**$ 742.9**	$ 2,423.5	$ 1,610.1	$ 970.6	$ 838.4	$ 881.1
Upstream						
Corporate Acquisitions	**–**	296.5	931.1	1,021.5	813.5	–
Property Acquisitions						
– North America	**21.4**	316.1	358.8	50.7	19.6	11.9
– International	**63.4**	122.7	136.0	–	–	–
Midstream						
Corporate Acquisitions/(Dispositions)	**–**	(655.2)	884.7	–	–	–
Property Acquisitions – Storage	**–**	69.9	–	–	–	–
Total Net Capital Investment	**$ 827.7**	$ 2,573.5	$ 3,920.7	$ 2,042.8	$ 1,671.5	$ 893.0

Supplemental Oil and Gas Operating Statistics *(Unaudited)*

For the three months ended March 31, 2002

OPERATING STATISTICS

SALES	2002 Q1	2001 Year	2001 Q4	2001 Q3	2001 Q2	2001 Q1	2000	1999	1998	1997
Produced Gas *(MMcf/day)*										
Canada	**1,346**	1,106	1,173	1,176	1,029	1,043	989	904	714	575
United States	**293**	217	259	219	212	178	82			
	1,639	1,323	1,432	1,395	1,241	1,221	1,071	904	714	575
Oil and Natural Gas Liquids *(bbls/day)*										
North America										
Conventional Light and Medium Oil	**4,339**	4,802	4,543	4,680	4,914	5,077	7,358	9,423	10,620	10,783
Conventional Heavy Oil	**46,765**	40,909	40,796	43,752	41,248	37,779	33,612	23,284	12,407	13,171
Natural Gas Liquids										
– Canada	**5,406**	4,998	5,529	4,762	4,887	4,805	4,771	5,135	5,877	4,856
– United States	**3,153**	2,291	2,855	2,536	2,201	1,556	723	–	–	–
Total North America Conventional	**59,663**	53,000	53,723	55,730	53,250	49,217	46,464	37,842	28,904	28,810
Syncrude	**31,548**	30,687	32,347	28,938	29,162	32,319	27,897	30,649	28,953	28,447
Total North America	**91,211**	83,687	86,070	84,668	82,412	81,536	74,361	68,491	57,857	57,257
International	**38,774**	51,899	51,055	51,472	53,498	51,582	43,883	27,347	2,217	1,683
Total	**129,985**	135,586	137,125	136,140	135,910	133,118	118,244	95,838	60,074	58,940
PER-UNIT RESULTS										
Produced Gas – Canada *($/Mcf)*										
Price, net of transportation and selling	**3.20**	5.25	2.98	3.26	6.02	9.37	5.32	2.48	2.04	2.04
Royalties	**0.65**	1.18	0.60	0.73	1.44	2.11	1.00	0.43	0.29	0.31
Operating costs	**0.55**	0.51	0.54	0.51	0.51	0.47	0.43	0.43	0.42	0.40
Netback	**2.00**	3.56	1.84	2.02	4.07	6.79	3.89	1.62	1.33	1.33
Produced Gas – United States *(C$/Mcf)*										
Price, net of transportation and selling	**3.35**	5.51	3.48	3.93	6.72	9.04	6.83			
Royalties	**0.65**	1.04	0.64	0.77	1.31	1.67	1.19			
Production taxes	**0.26**	0.50	0.32	0.35	0.60	0.82	0.53			
Operating costs	**0.29**	0.29	0.29	0.23	0.27	0.35	0.19			
Netback including hedge	**2.15**	3.68	2.23	2.58	4.54	6.20	4.92			
Hedge(1)	**–**	0.21	–	–	–	0.73	1.87			
Netback excluding hedge	**2.15**	3.47	2.23	2.58	4.54	5.47	3.05			

(1) Relates to contract volume of approximately 121 MMcf/d from June 1, 2000 to October 31, 2000 and 66 MMcf/d from November 1, 2000 to March 31, 2001.

Supplemental Oil and Gas Operating Statistics *(Unaudited)*

For the three months ended March 31, 2002

OPERATING STATISTICS (continued)

	2002 Q1	2001 Year	2001 Q4	2001 Q3	2001 Q2	2001 Q1	2000	1999	1998	1997
Conventional Light and Medium Oil *($/bbl)*										
Price, net of transportation and selling	**31.09**	36.21	33.28	36.21	37.40	37.69	41.48	24.94	17.49	25.59
Royalties	**4.74**	6.23	4.52	7.09	6.66	6.52	7.53	4.07	2.73	4.81
Operating costs	**6.35**	6.21	6.46	6.36	5.82	6.17	6.16	5.49	5.26	5.99
Netback including hedge	**20.00**	23.77	22.30	22.76	24.92	25.00	27.79	15.38	9.50	14.79
Hedge(2)	**0.73**	2.51	10.04	–	–	–	–	–	–	–
Netback excluding hedge	**19.27**	21.26	12.26	22.76	24.92	25.00	27.79	15.38	9.50	14.79
Conventional Heavy Oil *($/bbl)*										
Price, net of transportation and selling	**22.05**	20.62	22.70	24.71	18.23	16.20	28.45	20.30	9.40	15.41
Royalties	**1.90**	2.40	2.01	3.14	2.06	2.33	3.78	2.15	1.05	2.57
Operating costs	**4.75**	4.78	4.52	4.90	4.93	4.76	4.35	4.03	4.54	5.54
Netback including hedge	**15.40**	13.44	16.17	16.67	11.24	9.11	20.32	14.12	3.81	7.30
Hedge(2)	**0.73**	2.51	10.04	–	–	–	–	–	–	–
Netback excluding hedge	**14.67**	10.93	6.13	16.67	11.24	9.11	20.32	14.12	3.81	7.30
Total Conventional Oil *($/bbl)*										
Price, net of transportation and selling	**22.81**	22.23	23.60	25.83	20.26	18.75	30.79	21.64	13.13	19.99
Royalties	**2.14**	2.79	2.21	3.52	2.55	2.83	4.45	2.70	1.82	3.58
Operating costs	**4.88**	4.95	4.79	5.04	5.02	4.93	4.68	4.45	4.82	5.70
Netback including hedge	**15.79**	14.49	16.60	17.27	12.69	10.99	21.66	14.49	6.49	10.71
Hedge(2)	**0.73**	2.51	10.04	–	–	–	–	–	–	–
Netback excluding hedge	**15.06**	11.98	6.56	17.27	12.69	10.99	21.66	14.49	6.49	10.71
Natural Gas Liquids *($/bbl)*										
Price, net of transportation and selling	**27.49**	34.92	24.41	34.97	40.30	42.96	39.03	20.47	16.86	23.97
Royalties	**7.46**	10.24	7.29	9.62	12.02	12.92	10.69	5.58	4.52	6.11
Netback	**20.03**	24.68	17.12	25.35	28.28	30.04	28.34	14.89	12.34	17.86

(2) Relates to share of contract volume of 85,000 bbls/d for January to March 2002 and 100,000 bbls/d for September to December 2001. Ecuador amounts in 1999 represent the cost associated with hedges acquired with the acquisition of Pacalta Resources Ltd.

Supplemental Oil and Gas Operating Statistics *(Unaudited)*

For the three months ended March 31, 2002

OPERATING STATISTICS (continued)

	2002	2001								
	Q1	Year	Q4	Q3	Q2	Q1	2000	1999	1998	1997
Syncrude *($/bbl)*										
Price, net of transportation and selling	**34.86**	42.02	41.83	40.74	42.27	43.17	44.47	27.96	20.46	27.80
Gross overriding royalty and other revenue	**0.13**	0.64	0.13	0.19	2.15	0.18	0.23	0.58	0.51	0.69
Royalties	**(0.23)**	3.08	(0.60)	4.95	4.41	3.94	7.78	0.52	(0.03)	2.70
Cash operating costs	**17.73**	19.74	16.54	20.75	21.54	20.48	17.67	12.69	13.67	13.82
Netback including hedge	**17.49**	19.84	26.02	15.23	18.47	18.93	19.25	15.33	7.33	11.97
Hedge(2)	**0.80**	2.67	10.05	–	–	–	–	–	–	–
Netback excluding hedge	**16.69**	17.17	15.97	15.23	18.47	18.93	19.25	15.33	7.33	11.97
Ecuador Oil *($/bbl)*										
Price, net of transportation and selling	**22.07**	26.24	23.62	28.43	28.12	24.71	33.17	20.79		
Royalties	**7.05**	8.10	5.85	9.76	8.72	8.05	13.22	7.64		
Operating costs	**5.78**	4.98	4.70	5.04	5.63	4.53	4.14	3.55		
Netback including hedge	**9.24**	13.16	13.07	13.63	13.77	12.13	15.81	9.60		
Hedge(2)	**0.07**	1.09	4.40	–	–	–	–	(4.29)		
Netback excluding hedge	**9.17**	12.07	8.67	13.63	13.77	12.13	15.81	13.89		

(2) Relates to share of contract volume of 85,000 bbls/d for January to March 2002 and 100,000 bbls/d for September to December 2001. Ecuador amounts in 1999 represent the cost associated with hedges acquired with the acquisition of Pacalta Resources Ltd.

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