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ORIGINAL

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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FORM 6-K

Report of Foreign Issuer

Pursuant to Rule 13a-16 or 15d-16 of the Securities Exchange Act of 1934

PE

For: July 25, 2002

ALBERTA ENERGY COMPANY LTD.

(Translation of registrant's name into English)

1800, 855 – 2nd Street S.W. PO Box 2850

Calgary, Alberta, Canada T2P 2S5

(Address of principal executive office)

PROCESSED JUL 30 2002 THOMSON FINANCIAL

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F: Form 40-F: ✓

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes No ✓

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): N/A .

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALBERTA ENERGY COMPANY LTD.
(Registrant)

By: Trudy M.

Name: Trudy M. Curran
Title: Assistant Corporate Secretary

Date: July 25, 2002

Form 6-K Exhibit Index

Exhibit No.

The following items were provided to the sole shareholder of Alberta Energy Company Ltd., and were filed concurrently with each of The Toronto Stock Exchange and the New York Stock Exchange, as well as the Canadian Securities Commissions:

1. Consolidated Financial Statements for the six months ended June 30, 2002.

2. Management's Discussion and Analysis for the six months ended June 30, 2002.

In addition, the following items were filed with the Canadian Securities Commissions:

3. Financial Coverage on Long-Term Debt

4. Comfort Letter, dated July 25, 2002, from PricewaterhouseCoopers LLP in relation to the Corporation's interim financial statements for the six months ended June 30, 2002.

Consolidated Financial Statements
For the period ended June 30, 2002

Alberta Energy Company Ltd.

(a wholly owned subsidiary of EnCana Corporation)

Consolidated Statement of Earnings

(unaudited) ($ millions)		June 30 Three Months Ended 2002	2001	Six Months Ended 2002	2001
Revenues, Net of Royalties and Production Taxes	*(note 3)*	**$ 1,355**	$ 1,600	**$ 2,557**	$ 3,650
Expenses	*(note 3)*				
Transportation and selling		**104**	100	**207**	177
Operating		**280**	217	**482**	426
Purchased product		**407**	610	**813**	1,393
Administrative		**20**	17	**44**	33
Interest, net		**81**	47	**142**	97
Foreign exchange		**(85)**	(58)	**(86)**	19
Depreciation, depletion and amortization		**412**	314	**714**	567
Loss on sale of assets		**22**	-	**22**	-
		1,241	1,247	**2,338**	2,712
Net Earnings Before the Undernoted		**114**	353	**219**	938
Income tax expense	*(note 6)*	**58**	100	**97**	350
Non-controlling interest	*(note 5)*	**(1)**	-	**(1)**	-
Net Earnings from Continuing Operations		**57**	253	**123**	588
Non-Controlling Interest from Discontinued Operations		**(3)**	-	**(3)**	-
Net Earnings from Discontinued Operations	*(note 4)*	**3**	14	**9**	10
Net Earnings		**63**	267	**135**	598
Distributions on Preferred Securities, Net of Tax		**-**	10	**16**	21
Net Earnings Attributable to Common Shareholders		**$ 63**	$ 257	**$ 119**	$ 577

Consolidated Statement of Retained Earnings

(unaudited) ($ millions)		June 30 Six Months Ended 2002	2001
Retained Earnings, Beginning of Year			
As previously reported		**$ 1,788**	$ 1,264
Retroactive adjustment for change in accounting policy	*(note 2)*	**-**	(29)
As Restated		**1,788**	1,235
Charges for Normal Course Issuer Bid		**(15)**	(58)
Net Earnings		**135**	598
Dividends on Common Shares		**(66)**	(90)
Distributions on Preferred Securities, Net of Tax		**(16)**	(21)
Retained Earnings, End of Period		**$ 1,826**	$ 1,664

See accompanying notes to Consolidated Financial Statements

Consolidated Balance Sheet

(unaudited) ($ millions)		As at June 30 2002	As at December 31 2001
Assets			
Current Assets			
Cash and cash equivalents		**$ 29**	$ 56
Accounts receivable and accrued revenue		**1,058**	935
Income tax receivable		**126**	-
Inventories		**444**	320
		1,657	1,311
Capital Assets, net		**12,824**	11,023
Investments and Other Assets		**314**	314
Assets of Discontinued Operations	*(note 4)*	**1,783**	1,450
		$ 16,578	$ 14,098
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,228**	$ 980
Income tax payable		**-**	242
Current portion of long-term debt	*(note 7)*	**-**	25
		1,228	1,247
Long-Term Debt	*(note 7)*	**5,238**	3,658
Due to EnCana Corporation	*(note 8)*	**571**	-
Other Liabilities		**216**	204
Future Income Taxes		**2,016**	2,174
Non-Controlling Interest	*(note 5)*	**624**	-
Liabilities of Discontinued Operations	*(note 4)*	**1,083**	858
		10,976	8,141
Shareholder's Equity			
Preferred securities		**420**	859
Share capital		**3,077**	3,052
Contributed surplus	*(note 5)*	**178**	-
Retained earnings		**1,826**	1,788
Foreign currency translation adjustment		**101**	258
		5,602	5,957
		$ 16,578	$ 14,098

See accompanying notes to Consolidated Financial Statements

Consolidated Statement of Cash Flows

		June 30			
		Three Months Ended		Six Months Ended	
(unaudited) ($ millions)		**2002**	2001	**2002**	2001
Operating Activities					
Net earnings from continuing operations		**$ 57**	$ 253	**$ 123**	$ 588
Depletion, depreciation and amortization		**412**	314	**714**	567
Future income taxes		**(205)**	18	**(192)**	152
Non-controlling interest - continuing operations		**(1)**	-	**(1)**	-
Other		**(74)**	(55)	**(65)**	28
Cash flow from continuing operations		**189**	530	**579**	1,335
Cash flow from discontinued operations		**24**	28	**40**	31
Cash flow		**213**	558	**619**	1,366
Net change in non-cash working capital from continuing operations		**65**	16	**(185)**	334
Net change in non-cash working capital from discontinued operations		**7**	7	**13**	6
		285	581	**447**	1,706
Investing Activities					
Corporate acquisition	*(note 5)*	**69**	-	**69**	(435)
Capital expenditures		**(1,053)**	(670)	**(1,866)**	(1,650)
Equity investments		**6**	-	**6**	(27)
Proceeds on disposal of assets		**232**	91	**268**	116
Net change in investments and other		**21**	9	**14**	(12)
Net change in non-cash working capital		**(204)**	(329)	**(98)**	(88)
Discontinued operations		**(12)**	(36)	**(21)**	(12)
		(941)	(935)	**(1,628)**	(2,108)
Financing Activities					
Issuance of long-term debt		**486**	648	**1,091**	680
Issuance of intercorporate debt		**211**	-	**211**	-
Issuance of common shares		**4**	18	**34**	39
Purchase of common shares		**(1)**	(87)	**(25)**	(87)
Dividends on common shares		**-**	(90)	**(66)**	(90)
Payments to preferred securities holders		**(5)**	(10)	**(16)**	(21)
Net change in non-cash working capital		**-**	(9)	**(12)**	(17)
Other		**(32)**	30	**(56)**	47
Discontinued operations		**(5)**	(3)	**(7)**	(5)
		658	497	**1,154**	546
Increase (Decrease) in Cash and Cash Equivalents		**2**	143	**(27)**	144
Cash and Cash Equivalents, Beginning of Period		**27**	13	**56**	12
Cash and Cash Equivalents, End of Period		**$ 29**	$ 156	**$ 29**	$ 156

See accompanying notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements *(unaudited)*

1. Basis of Presentation

The interim consolidated financial statements include the accounts of Alberta Energy Company Ltd. and its subsidiaries (the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration, production and marketing of natural gas and crude oil, as well as pipelines, natural gas liquids processing and gas storage operations.

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the annual audited consolidated financial statements for the year ended December 31, 2001, except as described in Note 2. 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.

On January 27, 2002, the Company and PanCanadian Energy Corporation ("PanCanadian") announced plans to combine their companies. The transaction, which closed on April 5, 2002, was accomplished through a plan of arrangement (the "Arrangement") under the Business Corporations Act (Alberta). On April 5, 2002, PanCanadian changed its name to EnCana Corporation ("EnCana"). The Company is now an indirect wholly owned subsidiary of EnCana.

2. Changes in Accounting Policies

Foreign Currency Translation

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.

3. Segmented Information

Due to the business combination as described in Note 1, the Company has redefined its operations into the following segments. Onshore North America includes the Company's North America onshore exploration for, and production of, natural gas and crude oil. Offshore & International combines the Offshore & International Operations Division exploration for, and production of, crude oil and natural gas in Ecuador and Gulf of Mexico with the Offshore & New Ventures Exploration Division exploration activity on the North American frontier region, the Gulf of Mexico and Latin America. Midstream & Marketing includes pipelines, natural gas liquids processing and gas storage operations, as well as, ancilliary activities related to the marketing of the Company's natural gas and crude oil production. All prior periods have been restated to conform to these definitions. Operations that have been discontinued are disclosed in Note 4.

Notes to Consolidated Financial Statements *(unaudited)*

3. Segmented Information (continued)

($ millions)

RESULTS OF OPERATIONS (FOR THE THREE MONTHS ENDED)

	Onshore North America		Offshore & International		Midstream & Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 819**	$ 966	**$ 182**	$ 154	**$ 554**	$ 725
Royalties and production taxes	**141**	202	**59**	43	**-**	-
Revenues, net of royalties and production taxes	**678**	764	**123**	111	**554**	725
Expenses						
Transportation and selling	**48**	40	**10**	16	**46**	44
Operating	**166**	135	**43**	42	**71**	40
Purchased product	**-**	-	**-**	-	**407**	610
Depreciation, depletion and amortization	**250**	209	**122**	93	**35**	9
Loss on sale of assets	**-**	-	**17**	-	**5**	-
Segment Income (Loss)	**$ 214**	$ 380	**$ (69)**	$ (40)	**$ (10)**	$ 22

	Corporate		Consolidated	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ -**	$ -	**$ 1,555**	$ 1,845
Royalties and production taxes	**-**	-	**200**	245
Revenues, net of royalties and production taxes	**-**	-	**1,355**	1,600
Expenses				
Transportation and selling	**-**	-	**104**	100
Operating	**-**	-	**280**	217
Purchased product	**-**	-	**407**	610
Depreciation, depletion and amortization	**5**	3	**412**	314
Loss on sale of assets	**-**	-	**22**	-
Segment Income (Loss)	**(5)**	(3)	**130**	359
Administrative	**20**	17	**20**	17
Interest, net	**81**	47	**81**	47
Foreign exchange	**(85)**	(58)	**(85)**	(58)
Other	**-**	-	**-**	-
Net (Loss) Earnings Before Income Tax	**(21)**	(9)	**114**	353
Income tax expense	**58**	100	**58**	100
Non-controlling interest			**(1)**	-
Net (Loss) Earnings from Continuing Operations	**$ (79)**	$ (109)	**$ 57**	$ 253

Notes to Consolidated Financial Statements *(unaudited)*

3. Segmented Information (continued)

GEOGRAPHIC AND PRODUCT INFORMATION (FOR THE THREE MONTHS ENDED)

Onshore North America

	Produced Gas & NGL's			
	Canada		U.S. Rockies	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 434**	$ 614	**$ 146**	$ 142
Royalties and production taxes	**88**	140	**36**	39
Revenues, net of royalties and production taxes	**346**	474	**110**	103
Expenses				
Transportation and selling	**31**	29	**11**	4
Operating	**62**	51	**11**	5
Operating cash flow	**$ 253**	$ 394	**$ 88**	$ 94

	Conventional Crude Oil		Syncrude		Total Onshore North America	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 148**	$ 90	**$ 91**	$ 120	**$ 819**	$ 966
Royalties and production taxes	**16**	11	**1**	12	**141**	202
Revenues, net of royalties and production taxes	**132**	79	**90**	108	**678**	764
Expenses						
Transportation and selling	**5**	5	**1**	2	**48**	40
Operating	**25**	21	**68**	58	**166**	135
Operating cash flow	**$ 102**	$ 53	**$ 21**	$ 48	**$ 464**	$ 589

Offshore & International

	Ecuador		Other International		Total Offshore & International	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 182**	$ 153	**$ -**	$ 1	**$ 182**	**$** 154
Royalties and production taxes	**59**	43	**-**	-	**59**	43
Revenues, net of royalties and production taxes	**123**	110	**-**	1	**123**	111
Expenses						
Transportation and selling	**10**	16	**-**	-	**10**	16
Operating	**31**	27	**12**	15	**43**	42
Operating cash flow	**$ 82**	$ 67	**$ (12)**	$ (14)	**$ 70**	$ 53

Midstream & Marketing

	Midstream		Marketing		Total Midstream & Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 100**	$ 178	**$ 454**	$ 547	**$ 554**	$ 725
Expenses						
Transportation and selling	**-**	-	**46**	44	**46**	44
Operating	**29**	34	**42**	6	**71**	40
Purchased product	**51**	105	**356**	505	**407**	610
Operating cash flow	**$ 20**	$ 39	**$ 10**	$ (8)	**$ 30**	$ 31

Notes to Consolidated Financial Statements *(unaudited)*

3. Segmented Information (continued)

($ millions)

RESULTS OF OPERATIONS (FOR THE SIX MONTHS ENDED)

	Onshore North America		Offshore & International		Midstream & Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 1,573**	$ 2,251	**$ 271**	$ 284	**$ 1,053**	$ 1,664
Royalties and production taxes	**257**	469	**83**	80	**-**	-
Revenues, net of royalties and production taxes	**1,316**	1,782	**188**	204	**1,053**	1,664
Expenses						
Transportation and selling	**99**	71	**22**	31	**86**	75
Operating	**317**	270	**73**	73	**92**	83
Purchased product	**-**	-	**-**	-	**813**	1,393
Depreciation, depletion and amortization	**509**	411	**157**	133	**40**	17
Loss on sale of assets	**-**	-	**17**	-	**5**	-
Segment Income (Loss)	**$ 391**	$ 1,030	**$ (81)**	$ (33)	**$ 17**	$ 96

	Corporate		Consolidated	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ -**	$ -	**$ 2,897**	$ 4,199
Royalties and production taxes	**-**	-	**340**	549
Revenues, net of royalties and production taxes	**-**	-	**2,557**	3,650
Expenses				
Transportation and selling	**-**	-	**207**	177
Operating	**-**	-	**482**	426
Purchased product	**-**	-	**813**	1,393
Depreciation, depletion and amortization	**8**	6	**714**	567
Loss on sale of assets	**-**	-	**22**	-
Segment Income (Loss)	**(8)**	(6)	**319**	1,087
Administrative	**44**	33	**44**	33
Interest, net	**142**	97	**142**	97
Foreign exchange	**(86)**	19	**(86)**	19
Net (Loss) Earnings Before Income Tax	**(108)**	(155)	**219**	938
Income tax expense	**97**	350	**97**	350
Non Controlling interest			**(1)**	-
Net (Loss) Earnings from Continuing Operations	**$ (205)**	$ (505)	**$ 123**	$ 588

Notes to Consolidated Financial Statements *(unaudited)*

3. Segmented Information (continued)

GEOGRAPHIC AND PRODUCT INFORMATION (FOR THE SIX MONTHS ENDED)

Onshore North America

	Produced Gas & NGL's			
	Canada		U.S. Rockies	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 869**	$ 1,539	**$ 253**	$ 297
Royalties and production taxes	**169**	343	**62**	81
Revenues, net of royalties and production taxes	**700**	1,196	**191**	216
Expenses				
Transportation and selling	**65**	50	**20**	8
Operating	**133**	102	**18**	11
Operating cash flow	**$ 502**	$ 1,044	**$ 153**	$ 197

	Conventional Crude Oil		Syncrude		Total Onshore North America	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 260**	$ 167	**$ 191**	$ 248	**$ 1,573**	$ 2,251
Royalties and production taxes	**26**	22	**-**	23	**257**	469
Revenues, net of royalties and production taxes	**234**	145	**191**	225	**1,316**	1,782
Expenses						
Transportation and selling	**12**	9	**2**	4	**99**	71
Operating	**48**	40	**118**	117	**317**	270
Operating cash flow	**$ 174**	$ 96	**$ 71**	$ 104	**$ 900**	$ 1,441

Offshore & International

	Ecuador		Other International		Total Offshore & International	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 271**	$ 282	**$ -**	$ 2	**$ 271**	$ 284
Royalties and production taxes	**83**	80	**-**	-	**83**	80
Revenues, net of royalties and production taxes	**188**	202	**-**	2	**188**	204
Expenses						
Transportation and selling	**22**	31	**-**	-	**22**	31
Operating	**51**	48	**22**	25	**73**	73
Operating cash flow	**$ 115**	$ 123	**$ (22)**	$ (23)	**$ 93**	$ 100

Midstream & Marketing

	Midstream		Marketing		Total Midstream & Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 231**	$ 483	**$ 822**	$ 1,181	**$ 1,053**	$ 1,664
Expenses						
Transportation and selling	**-**	-	**86**	75	**86**	75
Operating	**50**	70	**42**	13	**92**	83
Purchased product	**140**	298	**673**	1,095	**813**	1,393
Operating cash flow	**$ 41**	$ 115	**$ 21**	$ (2)	**$ 62**	$ 113

Notes to Consolidated Financial Statements *(unaudited)*

3. Segmented Information (continued)

CAPITAL EXPENDITURES

	Three Months Capital Expenditures		Six Months Capital Expenditures	
	2002	2001	**2002**	2001
Onshore North America	**$ 756**	$ 488	**$ 1,424**	$ 1,243
Offshore & International	**178**	133	**308**	261
Midstream & Marketing	**112**	38	**121**	128
Corporate	**7**	11	**13**	18
	$ 1,053	$ 670	**$ 1,866**	$ 1,650

CAPITAL AND TOTAL ASSETS

	As at			
	Capital Assets		Total Assets	
	June 30, 2002	*December 31, 2001*	***June 30, 2002***	*December 31, 2001*
Onshore North America	**$ 9,887**	$ 8,632	**$ 10,975**	$ 9,250
Offshore & International	**2,234**	1,904	**2,422**	2,023
Midstream & Marketing	**648**	439	**1,148**	1,226
Corporate	**55**	48	**250**	149
Assets from Discontinued Operations	**-**	-	**1,783**	1,450
	$ 12,824	$ 11,023	**$ 16,578**	$ 14,098

Notes to Consolidated Financial Statements *(unaudited)*

4. Discontinued Operations

Merchant Energy

On May 31, 2002, the Company acquired the Houston-based merchant energy operation from its parent company, EnCana Corporation, in exchange for common shares, as described in Note 5. A formal plan to dispose of these operations was adopted on April 24, 2002. Accordingly, the Company accounts for these operations as discontinued operations.

Pipelines

On July 9, 2002, the Company announced that it plans to sell its 70% interest in the Cold Lake Pipeline System and its 100% interest in the Express Pipeline System, both crude oil pipeline systems. Accordingly, these investments have been accounted for as discontinued operations.

Both of these discontinued operations were included in the Midstream and Marketing segment.

Consolidated Statement of Income *($ millions)*	For the three months ended June 30					
	Merchant Energy		Pipelines		Total	
	2002	2001	**2002**	2001	**2002**	2001
Gross Revenues	**$ 162**	$ -	**$ 58**	$ 57	**$ 220**	$ 57
Expenses						
Operating	**6**	-	**20**	18	**26**	18
Purchased product	**159**	-	**-**	-	**159**	-
Interest, net	**-**	-	**11**	12	**11**	12
Foreign exchange	**-**	-	**(10)**	(7)	**(10)**	(7)
Depreciation, depletion and amortization	**6**	-	**11**	12	**17**	12
Loss on discontinuance	**7**	-	**-**	-	**7**	-
	178	-	**32**	35	**210**	35
Net Earnings (Loss) Before Income Tax	**(16)**	-	**26**	22	**10**	22
Income tax expense	**(4)**	-	**11**	8	**7**	8
Net Earnings (Loss) from Discontinued Operations	**$ (12)**	$ -	**$ 15**	$ 14	**$ 3**	$ 14

	For the six months ended June 30					
	Merchant Energy		Pipelines		Total	
	2002	2001	**2002**	2001	**2002**	2001
Gross Revenues	**$ 162**	$ -	**$ 106**	$ 110	**$ 268**	$ 110
Expenses						
Operating	**6**	-	**34**	43	**40**	43
Purchased product	**159**	-	**-**	-	**159**	-
Interest, net	**-**	-	**22**	23	**22**	23
Foreign exchange	**-**	-	**(9)**	2	**(9)**	2
Depreciation, depletion and amortization	**6**	-	**24**	23	**30**	23
Loss on discontinuance	**7**	-	**-**	-	**7**	-
	178	-	**71**	91	**249**	91
Net Earnings (Loss) Before Income Tax	**(16)**	-	**35**	19	**19**	19
Income tax expense	**(4)**	-	**14**	9	**10**	9
Net Earnings (Loss) from Discontinued Operations	**$ (12)**	$ -	**$ 21**	$ 10	**$ 9**	$ 10

Notes to Consolidated Financial Statements *(unaudited)*

4. Discontinued Operations (continued)

Consolidated Balance Sheet *($ millions)*	As at June 30 Merchant Energy 2002	Merchant Energy 2001	Pipelines 2002	Pipelines 2001	Total 2002	Total 2001
Assets						
Cash and cash equivalents	$ -	$ -	$ 66	$ 31	$ 66	$ 31
Accounts receivable and accrued revenue	338	-	44	47	382	47
Inventories	-	-	1	1	1	1
	338	-	111	79	449	79
Capital assets, net	-	-	807	1,222	807	1,222
Investments and other assets	-	-	527	38	527	38
	338	-	1,445	1,339	1,783	1,339
Liabilities						
Accounts payable and accrued liabilities	240	-	68	69	308	69
Income tax payable	-	-	4	(2)	4	(2)
Current portion of long-term debt	-	-	23	21	23	21
	240	-	95	88	335	88
Long-term debt	-	-	546	570	546	570
Future income taxes	-	-	202	145	202	145
	240	-	843	803	1,083	803
Net Assets of Discontinued Operations	$ 98	$ -	$ 602	$ 536	$ 700	$ 536

For comparative purposes, the following tables show the results of Discontinued Operations on the Consolidated Financial Statements for the years ended December 31.

Consolidated Statement of Income *($ millions)*	Year ended December 31 Pipelines 2001	Pipelines 2000
Gross Revenues	$ 227	$ 144
Expenses		
Operating	85	49
Interest, net	46	24
Foreign exchange	10	8
Depreciation, depletion and amortization	50	33
	191	114
Net Earnings Before Income Taxes	36	30
Income tax expense	24	19
Net Earnings from Discontinued Operations	$ 12	$ 11

Notes to Consolidated Financial Statements *(unaudited)*

4. Discontinued Operations (continued)

Consolidated Balance Sheet *($ millions)*	As at December 31 Pipelines 2001	2000
Assets		
Cash and cash equivalents	$ 48	$ 33
Accounts receivable and accrued revenue	49	46
Inventories	1	-
	98	79
Capital assets, net	844	1,230
Investments and other assets	508	36
	1,450	1,345
Liabilities		
Accounts payable and accrued liabilities	63	65
Income tax payable	-	(3)
Current portion of long-term debt	24	16
	87	78
Long-term debt	584	573
Future income taxes	187	144
	858	795
Net Assets of Discontinued Operations	$ 592	$ 550

At June 30, 2002 and December 31, 2001, the Company's interest in the Cold Lake Pipeline System is held through its equity investment in the Cold Lake Pipeline Limited Partnership, which commenced operations on December 21, 2001. The Company earned its interest in the Cold Lake Pipeline Limited Partnership by continuing its existing interest in the original Cold Lake Pipeline System as well as contributing cash for its share of a new expansion pipeline between Cold Lake and Hardisty, Alberta and a pipeline lateral connecting producing areas with the Cold Lake Pipeline System. Prior to December 31, 2001, the Company owned the original Cold Lake Pipeline System through an indirect wholly owned subsidiary.

Notes to Consolidated Financial Statements *(unaudited)*

5. Related Party Transaction

On May 31, 2002, the Company, through its wholly owned subsidiary Alenco Inc., acquired, from its parent company, EnCana Corporation ("EnCana"), all of the common shares of EnCana Energy Holdings Inc. ("Holdings") and EnCana GOM Inc. ("GOM") in exchange for common shares representing approximately 33% ownership of Alenco Inc. Holdings and GOM collectively represent the upstream and midstream business carried on by EnCana in the United States. The acquisition of Holdings includes the Houston-based merchant energy operation which has been accounted for as discontinued operations, based on EnCana's adoption of formal plans to dispose of the operations on April 24, 2002.

The acquisition was accounted for using the historical book values recorded by EnCana. Upon completion of the transaction, the Company's share of the post acquisition shareholders' equity of Alenco Inc. increased and was recorded as Contributed Surplus.

6. Income Taxes

The provision for income taxes is as follows:

	Three months ended June 30		Six months ended June 30	
($ millions)	**2002**	2001	**2002**	2001
Current				
Canada	**$ 247**	$ 69	**$ 272**	$ 173
United States	**9**	(4)	**9**	3
Ecuador	**7**	17	**8**	21
Other	**-**	-	**-**	1
	263	82	**289**	198
Future	**(205)**	18	**(192)**	152
	$ 58	$ 100	**$ 97**	$ 350

7. Long-Term Debt

($ millions)	**As at June 30 2002**	As at December 31 2001
Canadian dollar debt		
Revolving credit and term loan borrowings	**$ 1,368**	$ 350
Unsecured debentures, including capital securities	**1,830**	1,425
	3,198	1,775
U.S. dollar debt		
U.S. unsecured senior notes	**1,819**	1,908
U.S. revolving credit and term loan borrowings	**221**	-
	5,238	3,683
Current portion of long-term debt	**-**	25
	$ 5,238	$ 3,658

Notes to Consolidated Financial Statements *(unaudited)*

8. Due to EnCana Corporation

Included in the amount Due to EnCana Corporation of $571 million is a $253 million promissory note, which bears interest at Canadian Bankers Acceptance plus 1%, and a US$238 million promissory note, which bears interest at 7.5%. The remaining balances are unsecured and non-interest bearing.

9. Reclassification

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

10. Subsequent Event

On July 25, 2002, the Board of Directors approved the issuance of Common Shares to EnCana Corporation for consideration of $650 million.

ALBERTA ENERGY COMPANY LTD.
Management's Discussion and Analysis

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing Alberta Energy Company Ltd. ("AEC" or the "Company") shareholder and potential investors with information regarding the Company, certain statements throughout this Interim Management's Discussion and Analysis ("MD&A") constitutes 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; oil and gas prices; the Company's oil, liquids and gas sales; the Company's cash flow and net earnings; the Company's production levels; the Company's share of Syncrude production; the impact of hedges on the Company's revenue; capital investment levels; the sources of funding for capital investments; and the proposed disposition of the Express and Cold Lake pipeline interests.

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 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 and development 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. 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 ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the six months ended June 30, 2002 and June 30, 2001 and the audited consolidated financial statements and MD&A for the year ended December 31, 2001.

CONSOLIDATED OVERVIEW

In the second quarter of 2002, AEC's net earnings from continuing operations were $57 million down from $253 million. Cash flow from continuing operations for the period was $189 million, a decline from $530 million last year. Lower quarterly results are primarily due to lower natural gas prices in the second quarter of 2002.

For the year to date, net earnings from continuing operations were $123 million, a decrease of $465 million from the corresponding period of 2001. Year-to-date cash flow from continuing operations was $579 million compared with $1,335 million in the six months ended June 2001. The decline in results was largely due to significantly weaker market prices for natural gas, which were only partially offset by increased natural gas production.

Consolidated Financial Summary *($ millions)*	Three months ended June 30		Six months ended June 30	
	2002	2001	**2002**	2001
Revenues, net of royalties and production taxes	**$ 1,355**	$ 1,600	**$ 2,557**	$ 3,650
Net earnings from continuing operations	**57**	253	**123**	588
Net earnings attributable to common shareholders	**63**	257	**119**	577
Cash flow from continuing operations	**189**	530	**579**	1,335
Cash flow	**213**	558	**619**	1,366

On April 5, 2002, AEC and PanCanadian Energy Corporation ("PanCanadian") completed the merger of their two companies, creating EnCana Corporation ("EnCana"). The companies satisfied all closing conditions, including receipt of approvals from shareholders of PanCanadian, shareholders and optionholders of AEC, and the Court of Queen's Bench of Alberta. Under the terms of the merger, AEC shareholders received 1.472 EnCana common shares for each AEC common share owned. AEC is now an indirect wholly owned subsidiary of EnCana.

In May 2002, the Company expanded its production, land holdings and midstream assets in the U.S. Rocky Mountain region with the purchase of certain Colorado assets from subsidiaries of El Paso Corporation for approximately $420 million. This acquisition complements the Company's existing Piceance Basin gas production at Mamm Creek and the surrounding area near Rifle, Colorado.

On May 31, 2002, one of AEC's subsidiaries acquired certain related companies, through an exchange of shares, from its ultimate parent company, EnCana. The companies acquired collectively represent the upstream and midstream business carried on by EnCana in the United States. As a result of this transaction, a non-controlling interest of $1 million has been reflected in the Company's second quarter and year-to-date net earnings from continuing operations, representing EnCana's non-controlling ownership in one of the Company's subsidiaries. Included in the acquired U.S. operations is a Houston-based merchant energy operation that is anticipated to be wound-down by the end of the third quarter of 2002. Consequently, second quarter and year-to-date results include an after-tax loss of $12 million, the results of the discontinued operations from the date of acquisition.

On July 9, 2002, the Company announced plans to dispose of two major crude oil pipeline systems. The proposed disposition includes the Company's indirect 100 percent interest in the Express Pipeline System and its indirect 70 percent interest in the Cold Lake Pipeline System. It is anticipated that, upon the proposed disposition, capital will be re-deployed into exploration and production initiatives that are more consistent with the Company's strategic direction.

The merchant energy and pipeline operations described above have both been accounted for as discontinued operations and the financial statements have been restated to reflect these discontinued operations as described in Note 4 to unaudited interim consolidated financial statements ("Consolidated Financial Statements").

BUSINESS ENVIRONMENT

	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	**2002**	2001
Average AECO Price ($ per thousand cubic feet)	**4.42**	7.38	**3.88**	9.37
Average NYMEX Price (US$ per million British thermal units)	**3.38**	4.39	**2.80**	5.31
WTI Average (US$ per barrel)	**26.27**	27.98	**23.95**	28.32
WTI-Bow River Differential (US$ per barrel)	**5.43**	10.94	**5.33**	11.40
Oriente Differential (Ecuador) (US$)	**3.78**	8.09	**4.35**	7.95
U.S./Canadian dollar exchange rate (US$)	**0.643**	0.649	**0.635**	0.652

Natural gas prices showed improvements in the second quarter of 2002, compared with price levels experienced in the first three months of the year. However, throughout the first six months of the year prices remained well below the historically high levels experienced during the same period of 2001. Natural gas prices continue to be negatively impacted by higher than expected natural gas storage levels resulting from lower demand in the North American market. The AECO index price per thousand cubic feet averaged $4.42 in the second quarter and $3.88 for the year to date compared with $7.38 and $9.37 in the respective periods of 2001.

Although down from the prior year, world crude oil prices remained more resilient in the first half of 2002 than the prices for natural gas. The benchmark West Texas Intermediate ("WTI") crude oil price averaged US$26.27 per barrel in the second quarter and US$23.95 per barrel for the year to date, down six percent and 15 percent respectively from the same periods of 2001. The WTI price in the second quarter of 2002 showed improvements over the first quarter's average price of US$21.63 per barrel. Oil prices have continued to strengthen through 2002 due to the production management agreement between OPEC and non-OPEC producers, problems with Iraqi crude oil deliveries, the war on terrorism and indications that the world economy is turning around.

The differential between heavy and light crude oil prices has narrowed dramatically compared with last year largely due to improvements in the supply/demand balance for heavy oil. The WTI-Bow River differential averaged US$5.43 per barrel in the second quarter and US$5.33 in the six months ended June 2002, a significant improvement over the respective periods of 2001. The resumption of operations at the CITGO refinery in Illinois and the start of the summer asphalt season helped to maintain the low differential averages realized in the first quarter.

RESULTS OF OPERATIONS
Upstream – (Onshore North America and Offshore & International)

	Three months ended June 30							
	2002				2001			
Financial Results *($ millions)*	**Produced Gas & NGL's**	**Conventional Crude Oil**	**Syncrude**	**Total**	Produced Gas & NGL's	Conventional Crude Oil	Syncrude	Total
Revenues								
Gross revenue	$ 580	$ 330	$ 91	$ 1,001	$ 756	$ 244	$ 120	$ 1,120
Royalties and production taxes	(124)	(75)	(1)	(200)	(179)	(54)	(12)	(245)
	456	255	90	801	577	190	108	875
Expenses								
Transportation and selling	42	15	1	58	33	21	2	56
Operating	73	68	68	209	56	63	58	177
Depreciation, depletion and amortization	-	-	-	372	-	-	-	302
Upstream income	$ 341	$ 172	$ 21	$ 162	$ 488	$ 106	$ 48	$ 340
Capital expenditures (excludes net acquisitions / dispositions)				$ 934				$ 621

	Six months ended June 30							
	2002				2001			
Financial Results *($ millions)*	**Produced Gas & NGL's**	**Conventional Crude Oil**	**Syncrude**	**Total**	Produced Gas & NGL's	Conventional Crude Oil	Syncrude	Total
Revenues								
Gross revenue	$ 1,122	$ 531	$ 191	$ 1,844	$ 1,836	$ 451	$ 248	$ 2,535
Royalties and production taxes	(231)	(109)	-	(340)	(424)	(102)	(23)	(549)
	891	422	191	1,504	1,412	349	225	1,986
Expenses								
Transportation and selling	85	34	2	121	58	40	4	102
Operating	151	121	118	390	113	113	117	343
Depreciation, depletion and amortization	-	-	-	666	-	-	-	544
Upstream income	$ 655	$ 267	$ 71	$ 327	$ 1,241	$ 196	$ 104	$ 997
Capital expenditures (excludes net acquisitions / dispositions)				$ 1,732				$ 1,504

Revenue Variances for 2002		Three months ended June 30			Six months ended June 30		
Compared to 2001	*($ millions)*	Price	Volume	Total	Price	Volume	Total
Produced gas and NGL's		$ (341)	$ 165	$ (176)	$ (1,072)	$ 358	$ (714)
Conventional crude oil		40	46	86	47	33	80
Syncrude		(9)	(20)	(29)	(34)	(23)	(57)
Total gross revenue		$ (310)	$ 191	$ (119)	$ (1,059)	$ 368	$ (691)

Revenues

In the second quarter, gross revenue of $1,001 million was down 11 percent, or $119 million, from the same quarter of 2001. Year-to-date gross revenues were $1,844 million, a 27 percent or $691 million, decline from the same period last year.

Produced Gas and NGL's

Produced gas and natural gas liquids revenues for the second quarter were down $176 million to $580 million compared with the second quarter of 2001. Produced gas sales volumes, which include the net impact of gas injections and withdrawals from gas storage, were 269 million cubic feet per day higher in the quarter than volumes in the same period of 2001, a 22 percent increase. The growth in natural gas sales volumes was more than offset by the considerably lower natural gas prices realized in the second quarter relative to the same period of 2001. Realized natural gas prices averaged $3.77 in the three months ended June 2002 compared with $6.09 per thousand cubic feet for the same period of 2001. A loss from currency and commodity hedging activities in the quarter decreased natural gas revenues by $30 million. There was no impact from hedging related activities in the second quarter of last year.

For the year to date, revenues from produced gas and natural gas liquids were $1,122 million, a decline of 39 percent from the same period in 2001. The lower results primarily reflect lower realized natural gas prices, which were down 54 percent from the first half of last year to an average of $3.55 per thousand cubic feet. Similar to the second quarter, the price decline was partially offset by increased natural gas sales volumes, which averaged 1,574 million cubic feet per day in the first six months of 2002, an increase of 343 million cubic feet per day over the same period of 2001. Hedging activities in the first six months decreased gross revenues related to natural gas by $20 million. There were no natural gas related hedging activities in the first half of 2001.

Conventional Crude Oil

Conventional crude oil revenues in the second quarter of 2002 were $330 million, compared with $244 million in the comparative quarter of 2001. Crude oil sales averaged 118,309 barrels per day in the second quarter compared with 99,660 barrels per day in the same quarter of 2001. Higher volume levels in the quarter reflect the increases related to the Foster Creek Steam-Assisted Gravity Drainage ("SAGD") project and improved volumes from Ecuador due to the timing of tanker shipments. The Company's realized prices from Onshore North America conventional crude oil averaged $26.85 per barrel in the quarter, up from $20.26 per barrel in the second quarter of 2001. Realized prices for Ecuador crude oil in the second quarter were $31.69 compared with $28.12 per barrel in the same period last year.

Compared with the first six months of 2001, revenues resulting from conventional crude oil sales increased by 18 percent to $531 million. The higher gross revenues are mainly attributable to increases in both realized crude oil prices and sales volumes in the Onshore North America division. Year-to-date realized crude oil prices in this division continue to benefit from the decrease in light-heavy oil differentials, averaging $24.98 per barrel compared with $19.54 per barrel in the corresponding period of 2001. In addition, sales volumes in the division were up 23%, or 10,276 barrels per day, in the first six months of the year, compared to the same period of 2001, as a result of increases from the Foster Creek SAGD project and increased production from Suffield.

Syncrude

Revenues from Syncrude were down $29 million in the second quarter of 2002 compared with the same quarter in 2001. In the three months ended June 2002, Syncrude sales averaged 24,295 barrels per day at an average realized price of $40.09 per barrel compared with 29,162 barrels per day at an average realized price of $42.27 per barrel for the corresponding period of 2001. Sales for the quarter were negatively impacted by a longer than scheduled turnaround for coker maintenance in the quarter and are expected to improve over the remainder of the year.

For the year to date, Syncrude revenues amounted to $191 million, a decline of 23 percent from the $248 million reported in the first six months of last year. The drop in revenues reflects lower realized prices, $37.15 per barrel for the year-to-date compared to $42.74 in the corresponding period of 2001, and a reduction in sales volumes. Syncrude sales averaged 27,902 barrels per day in the first half of 2002, a drop of 2,830 barrels per day from the same period of 2001 as a result of the turnaround.

Royalties and Production Taxes

Royalties and production taxes were 20 percent of gross revenues compared with 22 percent in the second quarter of last year. For the year to date this rate was 18 percent compared with 22 percent for the same period of 2001. The decreased rates reflect substantially lower energy prices partially offset by production increases.

Expenses

Transportation and selling costs for the quarter totalled $58 million compared with $56 million in the same quarter of 2001. For the year to date, these costs were $121 million, an increase of $19 million over $102 million for the six months ended June 2001. The higher transportation costs are principally the result of increased sales volumes in the quarter and for the year to date compared with the same periods last year. For the purpose of the revenue variance discussion above, these costs have been netted against revenues in calculating the per unit realized prices for each commodity.

	Three months ended June 30		Six months ended June 30	
Unit Operating Expenses* *($ per unit)*	**2002**	2001	**2002**	2001
Produced gas *(per thousand cubic feet)*	**$ 0.54**	$ 0.50	**$ 0.54**	$ 0.51
Conventional crude oil *(per barrel)*	**6.32**	6.95	**6.42**	6.43
Per barrel of oil equivalent**	**4.14**	4.17	**4.07**	4.04
Syncrude *(per barrel)*	**30.47**	21.54	**23.31**	20.98

**excluding operating recoveries*

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

Conventional oil and gas operating expenses totalled $141 million in the second quarter of 2002 compared with $119 million in the same quarter of 2001. The higher expenses were mainly attributable to the growth in sales volumes relative to the second quarter of 2001. On a per unit basis, operating expenses decreased slightly to $4.14 from $4.17 per barrel of oil equivalent in the second quarter of 2001.

Year-to-date conventional oil and gas operating expenses were $272 million, up from $226 million in the corresponding period last year. Costs associated with production were $4.07 per barrel of oil equivalent, a marginal increase over $4.04 per barrel of oil equivalent for the first six months of 2001. These increments in per unit costs were mainly due to increased production levels from higher operating cost properties.

For produced gas, unit operating costs were $0.54 per thousand cubic feet in the quarter compared with $0.50 in 2001 and $0.54 per thousand cubic feet for the year to date, up from $0.51 in the first half of last year.

Unit operating costs for crude oil fell nine percent in the quarter to $6.32 per barrel compared with the same quarter of 2001. This improvement reflects lower electricity costs in the second quarter of 2002 compared with 2001 and increased production from lower operating cost properties. For the year to date, operating costs were $6.42 per barrel compared to $6.43 per barrel for the same period last year.

For Syncrude, unit operating costs were $30.47 per barrel in the second quarter of 2002, a 41 percent increase from costs of $21.54 per barrel in the same quarter last year. Year-to-date unit costs for Syncrude were $23.31, which compares to $20.98 for the first half of 2001. The higher unit costs reflect the volume declines and increased costs associated with the coker turnaround delay.

Depreciation, depletion and amortization charges amounted to $372 million in the quarter and $666 million for the year to date, increases of $70 million and $122 million over the respective periods last year. These increases mainly reflect the impact of higher produced gas and crude oil volumes relative to the same periods in 2001.

Capital expenditures were $1,732 million in the first half of 2002 compared with $1,504 million spent in the first six months of 2001. $934 million of the year-to-date capital expenditures occurred in the second quarter of 2002, compared with $621 million in the same quarter last year. The majority of the year-to-date capital expenditures, 82 percent, were directed towards exploration and development in the Onshore North America division. The remainder was expended in the Offshore and International division, with primary focus on exploratory activity in the Gulf of Mexico and development activity in Ecuador.

During the second quarter, the Company completed the sale of its Columbia operations, which resulted in a loss of approximately $17 million. The Company also completed an impairment analysis of its holdings in the Northwest Shelf of Australia and determined that a write-down was required, which resulted in the recording of a $68 million loss in the quarter.

The Company drilled 296 wells in the second quarter, 99 percent of which were successful. For the year to date, 803 net wells have been drilled at a 99 percent success rate.

Midstream & Marketing

Financial Results* *($ millions)*	Three months ended June 30 2002	Three months ended June 30 2001	Six months ended June 30 2002	Six months ended June 30 2001
Revenues	**$ 554**	$ 725	**$ 1,053**	$ 1,664
Expenses				
Transportation and selling	**46**	44	**86**	75
Operating	**71**	40	**92**	83
Purchased product	**407**	610	**813**	1,393
Depreciation and amortization	**35**	9	**40**	17
	$ (5)	$ 22	**$ 22**	$ 96
Capital expenditures (excludes net acquisitions / dispositions)	**$ 112**	$ 38	**$ 121**	$ 128

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

Midstream revenues from continuing operations decreased 44 percent to $100 million in the second quarter of 2002 compared with the same period last year. For the six months ended June 2002, Midstream revenues were $231 million compared to $483 million for the same period in 2001. This decline was primarily due to the impact of lower natural gas prices on sales related to the gas storage facility optimization program.

Capital expenditures from continuing operations in the Midstream division were $112 million in the quarter up from $38 million in the same quarter of 2001. For the year to date, capital expenditures amounted to $121 million compared to $128 million in the first half of last year. The 2002 expenditures related primarily to ongoing improvements to midstream facilities. Expenditures in 2001 included the Transandino pipeline and Salt Plains gas storage acquisitions. The construction of the 450,000 barrel per day OCP pipeline in Ecuador is continuing on target for completion in the second quarter of 2003. To date $27 million has been invested related to the Company's 31.4% equity interest in the project.

The Company's purchased gas activity produced a margin, from continuing operations of $10 million in the second quarter down from $11 million in 2001. In the year to date, purchased gas activity from continuing operations resulted in a margin of $21 million, an increase of $23 million from the prior year. The increase was primarily due to favorable transportation mitigation strategies.

Corporate

In the second quarter of 2002, foreign exchange resulted in an $85 million gain compared to a $58 million gain in the same quarter of 2001. For the year to date, the total impact from foreign exchange was a $86 million gain, which compared to a $19 million expense in the first six months of last year. The majority of the foreign exchange impact results from the translation of U.S. dollar denominated debt where exchange gains and losses are recorded in earnings in the period they arise.

Net interest expense in the second quarter was $81 million, which contrasted with net interest expense of $47 million in the same quarter of 2001. For the six months ended June 30, 2002, net interest expense was $142 million, an increase over $97 million for the same period last year. The increase in net interest expense reflected the higher levels of net debt held by the Company during the quarter and the first six months of the year compared with the same periods of 2001.

Administrative expenses amounted to $20 million in the second quarter of 2002 compared to $17 million in the same period of 2001. Year-to-date administrative expenses were $44 million and $33 million in 2002 and 2001, respectively. The increases in administrative expenses, both on a quarterly and year to date basis, relate primarily to increased people and technology costs.

The provision for income taxes in the second quarter was $58 million, down from $100 million in the same quarter of last year. The year-to-date provision for income taxes was $97 million, down $253 million from the first six months of 2001. The decrease reflects the impact of lower operating results combined with an adjustment of $20 million to future income taxes resulting from a reduction in the Alberta corporate tax rate.

LIQUIDITY AND CAPITAL RESOURCES

AEC's cash flow from continuing operations was $189 million in the second quarter and $579 million for the year to date. In comparison, cash flow from continuing operations for the same periods of 2001 were $530 million and $1,335 million, respectively. Weaker energy prices in 2002 were the primary factor contributing to this decline.

Net capital expenditures of $821 million in the quarter, and $1,598 million for the year to date, include approximately $420 million related to the purchase of certain Colorado natural gas properties from subsidiaries of El Paso Corporation. This compares with net capital expenditures of $579 million in the second quarter of 2001 and $1,534 million for the six months ended June 30, 2001, which included the purchase of Ballard Petroleum in the first quarter. The Company's net investing for the year to date was funded by cash flow of $619 million and long-term debt.

RISK MANAGEMENT

Through the normal course of business, the Company is exposed to market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit and operational risks.

Exposure to market risks is managed by the Company through the use of various financial instruments. This risk management program is designed to enhance shareholder value by mitigating the volatility associated with commodity prices, exchange rates and interest rates, enhancing the probability of achieving corporate performance targets and locking in desirable rates of return on specific projects. As at June 30, 2002, the total unrecognized gain related to financial instruments was $110 million.

The risk of credit losses is minimized through the use of mandated credit policies and procedures designed to ensure that exposures are held within acceptable levels. With the exception of Ecuador oil sales, AEC does not have a significant concentration of credit risk with any single counterparty and bad debts incurred or provided for to date in 2002 are not material. All of the proceeds from the sale of the Company's crude oil Production in Ecuador are received from one marketing company. Accounts receivables on these sales are supported by letters of credit issued by a major international financial institution.

Operational risks are managed through a comprehensive insurance program designed to protect the Company from any significant losses arising from the risk exposures. Safety and environment risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors.

OUTLOOK

The Company continues to be optimistic about results for the remainder of 2002. Sales for 2002 are forecast to be between 1,525 and 1,575 million cubic feet per day for produced natural gas and between 142,000 and 153,000 barrels per day of oil and natural gas liquids. The pricing environment is expected to remain volatile. However, continued weakness in North American gas supply along with effective management of OPEC production should help in firming energy prices. The Company's hedging program is expected to reduce the negative effect of any market price declines.

Capital investment in core programs is expected to be approximately $3.4 billion before dispositions. It is expected the Company will be able to fund this program largely from cash flow together with proceeds received on the disposition of non-core assets. Expenditures will continue to emphasize strong near-term production growth, particularly in natural gas, while developing offshore and international projects for medium and longer-term value creation.

Alberta Energy Company Ltd.

1800, 855 – 2nd Street SW, PO Box 2850
Calgary, Alberta T2P 2S5

July 26, 2002

To: Canadian Securities Commissions

In accordance with continuous disclosure obligations of National Instrument 44-102 of the Canadian Securities Administrators, attached hereto for filing are the interest coverage ratios (the "Coverage Ratios") for Alberta Energy Company Ltd. ("AEC") for the twelve months ended June 30, 2002. The Coverage Ratios are to be considered as being appended to AEC's unaudited comparative financial statements for the six months ended June 30, 2002.

AEC is making this filing of the Coverage Ratios in connection with its Medium Term Note debenture program, which was established pursuant to a final short form prospectus dated August 2, 2001 that was filed with securities regulatory authorities in all provinces of Canada.

ALBERTA ENERGY COMPANY LTD.

Per: *"Kerry D. Dyte"*

Name: Kerry D. Dyte
Title: Corporate Secretary

Alberta Energy Company Ltd.
Financial Coverage on Long-Term Debt
($ millions, except ratios)

Interest Coverage on Long-Term Debt (earnings basis) *(1)*

	12 months ended December 31, 2001		12 months ended June 30, 2002	
Net earnings	824	(A)	361	(A)
Add: Interest,net	256		300	
Income taxes	443		195	
	1,523		856	
Interest,net	256		300	
Capitalized interest	15		7	
	271		307	
Interest coverage ratio	5.62		2.79	

(A) Includes gain on sale of assets of $238.1 for the 12 months ended December 31, 2001 and $216.1 for June 30, 2002.

Interest Coverage on Long-Term Debt (cash flow basis) *(1)*

Cash flow from Operations	2,023	1,276
Plus: Interest, net	256	300
Cash income taxes	357	448
	2,636	2,025
Interest	271	307
Interest coverage ratio	9.72	6.59

(1) The interest coverage ratios have been calculated without including the annual carrying charges relating to the aggregate principal amount of AEC's four issues of preferred securities ("the Preferred Securities") outstanding. If the Preferred Securities were classified as long-term debt, the carrying charges would be included in interest, net. If these annual carrying charges had been included in the calculations, the interest coverage ratios would have been:

	12 months ended December 31, 2001	12 months ended June 30, 2002
Interest coverage on long-term debt (earnings basis)	4.40	2.29
Interest coverage on long-term debt (cash flow basis)	7.61	5.43

PRICEWATERHOUSECOOPERS

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July 25, 2002

The Securities Commission or
Similar Authority in each of the
Provinces of Canada

Dear Sirs

Re: Alberta Energy Company Ltd.

We are the auditors of above Company and under date of February 8, 2002 we reported on the following financial statements of the Company incorporated by reference in the Short Form Prospectus dated August 2, 2001 relating to the issue and sale of $500,000,000 of Medium Term Note Debentures and in the Short Form Prospectus dated August 22, 2000 relating to the issue and sale of US$1,000,000,000 of debt securities (collectively, the "Prospectuses"):

- Balance sheets as at December 31, 2001 and 2000;
- Consolidated statements of earnings, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2001.

The Prospectuses also incorporate by reference the following unaudited interim consolidated financial statements of the Company:

- Consolidated balance sheet as at June 30, 2002;
- Consolidated statements of earnings, retained earnings and cash flows for the three and six months ended June 30, 2002 and 2001.

We have not audited any financial statements of the Company as at any date or for any period subsequent to December 31, 2001. Although we have performed an audit for the year ended December 31, 2001, the purpose and, therefore, the scope of the audit was to enable us to express our opinion on the financial statements as at December 31, 2001 and for the year then ended, but not on the financial statements for any interim period within that year. Therefore, we are unable to and do not express an opinion on the above-mentioned unaudited interim consolidated financial statements, or on the financial position, results of operations or cash flows of the Company as at any date or for any period subsequent to December 31, 2001.

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We have, however, performed a review of the unaudited interim consolidated financial statements of the Company as at June 30, 2002 and for the three and six months ended June 30, 2002 and 2001. We performed our review in accordance with Canadian generally accepted standards for a review of interim financial statements by an entity's auditor. Such an interim review consists principally of applying analytical procedures to financial data, and making enquiries of, and having discussions with, persons responsible for financial and accounting matters. An interim review is substantially less in scope than an audit, whose objective is the expression of an opinion regarding the financial statements. An interim review does not provide assurance that we would become aware of any or all significant matters that might be identified in an audit.

Based on our review, we are not aware of any material modification that needs to be made for these interim financial statements to be in accordance with Canadian generally accepted accounting principles.

This letter is provided solely for the purpose of assisting the securities regulatory authorities to which it is addressed in discharging their responsibilities and should not be used for any other purpose. Any use that a third party makes of this letter, or any reliance or decisions made based on it, are the responsibility of such third parties. We accept no responsibility for loss or damages, if any, suffered by any third party as a result of decisions made or actions taken based on this letter.

Yours very truly,

signed ("PricewaterhouseCoopers LLP")

Chartered Accountants