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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SEC MAIL PROCESSING RECEIVED MAY 31 2002 WASH, D.C. 155 SECTION

FORM 6-K

**Report of Foreign Private Issuer
Pursuant to Rule 13a-16 or 15d-16 of
the Securities Exchange Act of 1934**

For the month of May, 2002

BAYTEX ENERGY LTD.
(Translation of registrant's name into English)

PROCESSED
JUN 12 2002
THOMSON FINANCIAL

**2200, 205 – 5TH AVENUE S.W.
CALGARY, ALBERTA, CANADA
T2P 2V7**
(Address of principal executive office)

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 __X_

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 _X__

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-_______.

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.

BAYTEX ENERGY LTD.
(Registrant)

By:________________________________
Name: John G. Leach
Title: Vice President Finance and Administration

Dated: May 30, 2002

FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – MAY 14, 2002

Baytex Energy Ltd. (TSX-BTE) is pleased to announce its financial and operating results for the first quarter of 2002. These results clearly demonstrate the benefits of following a defined corporate strategy, the quality of our assets and the strength of our capital base. After enduring the longest slump in history for heavy oil prices, Baytex is enjoying the effects of a strong recovery of heavy oil fundamentals. Highlights of the first quarter include:

- Cash flow per share of $0.77 for the first quarter of 2002, 64% higher than the $0.47 for the fourth quarter of 2001. Under current production and pricing scenarios, cash flow for the second quarter of 2002 should reach $1.00 per share, 30% higher than that of the first quarter.

- Production for the first quarter averaged 38,948 boe/d. Current production is approximately 40,000 boe/d. The highly successful winter drilling program was entirely funded by cash flow from operations.

- Bank borrowings were reduced to $22.2 million as at March 31, 2002 as a result of the $120 million proceeds from asset dispositions and hedging gains. At the current rates of cash flow and capital spending, the Company's bank loans could be completely repaid during the third quarter of 2002.

A summary of our financial and operating results for the three months ended March 31, 2002 is presented as follows:

	Three Months Ended March 31		
	2002	2001	% Change
	(Unaudited)		
Petroleum & Natural Gas Sales ($000s)	**79,130**	79,230	-
Cash Flow From Operations ($000s)	**40,125**	37,617	7
Per Share ($) - Basic	**0.77**	0.82	(6)
- Diluted	**0.76**	0.80	(5)
Net Income (loss) ($000s)	**7,304**	(1,693)	n/a
Per Share ($) - Basic	**0.14**	(0.04)	n/a
- Diluted	**0.14**	(0.04)	n/a
Exploration & Development ($000s)	**39,991**	44,801	(11)
Dispositions – net ($000s)	**(46,363)**	(295)	n/a
Total Capital Expenditures ($000s)	**(6,372)**	44,506	n/a
Long-term Notes ($000s)	**330,249**	329,138	-
Bank Loans ($000s)	**22,179**	-	n/a
Other Working Capital ($000s)	**31,255**	(46,690)	n/a
Total Net Debt ($000s)	**383,683**	282,448	36
Daily Production			
Light Oil (Bbl/d)	**3,818**	3,911	(2)
Heavy Oil (Bbl/d)	**22,838**	25,970	(12)
Total Oil (Bbl/d)	**26,656**	29,881	(11)
Natural Gas (Mmcf/d)	**73.7**	57.6	28
Oil Equivalent (Boe/d @ 6:1)	**38,948**	39,483	(1)

	Three Months Ended March 31		
	2002	2001	% Change
	(Unaudited)		
Average Prices (Before Hedging)			
WTI Oil (US$/Bbl)	**21.64**	28.73	(25)
Edmonton Par Oil ($/Bbl)	**33.51**	43.00	(22)
BTE Light Oil ($/Bbl)	**27.58**	38.65	(29)
BTE Heavy Oil ($/Bbl)	**21.58**	14.62	48
BTE Total Oil ($/Bbl)	**22.44**	17.77	26
BTE Natural Gas ($/Mcf)	**3.19**	6.83	(53)
BTE Oil Equivalent ($/Boe)	**21.39**	23.41	(9)
Weighted Average Shares (000s)			
Basic	**52,027**	45,941	13
Diluted	**52,596**	47,066	12

Heavy Oil Pricing

Lloyd Blend (LLK) differentials staged a remarkable recovery in the first quarter of 2002. After averaging a post-deregulation high of US$10.69 per barrel (42% of WTI price) in 2001, LLK differentials declined to US$6.89 (35% of WTI), US$5.68 (27% of WTI) and US$4.93 (20% of WTI), respectively, in January, February and March of 2002. These recent differentials are more in-line with the long-term historical levels, where LLK differentials had averaged US$5.82 (29% of WTI) over the last 16 years since deregulation in 1985. Corporately, heavy oil wellhead prices recovered from the low of $7.95 per barrel in November 2001 to $15.68 in January, $20.33 in February and $27.97 in March of 2002. Baytex's heavy oil production netback averaged $12.92 per barrel during the first quarter this year, evidencing the attractive re-investment efficiency of this commodity under normal pricing as the Company's finding and development costs associated with heavy oil reserves are generally in the $5.00 range.

Operations Review

Capital expenditures for exploration and development activities totalled $40 million in the first quarter of 2002, and were entirely funded by cash flow from operations. This program included the drilling of 70 (64.8 net) wells, resulting in 31 (30.5 net) oil wells, 22 (17.8 net) gas wells, one (0.5 net) service well and 16 (16.0 net) dry holes. In terms of allocation between commodities, 35 of the wells drilled were targeting heavy oil, 32 for natural gas, two for light oil and one for water injection purposes.

When Baytex's 2002 capital budget was first set in early December, the Company had intended to defer heavy oil drilling until after spring break-up. With prices rebounding early in the new year, Baytex responded by accelerating the drilling of 35 wells into the first quarter and concurrently initiated a workover program to reactivate part of the shut-in production. The results of these actions were extremely rewarding, as heavy oil production averaged around 25,000 bbl/d in April, 16% higher than average production in December. Furthermore, the efficiency of the capital program is most evident here as capital expenditures of the Heavy Oil District in the first quarter totalled only $15 million, equating to the spending efficiency of $2,900 per barrel of production added, after accounting for normal production decline. Capital budget for the second quarter includes the drilling of 25 heavy oil wells with at least half of them in the Cold Lake property in Alberta. Although this property is currently producing only 1,300 bbl/d, it has the potential to become one of the Company's most significant heavy oil properties with second quarter drilling helping to delineate this prospect. Baytex, as planned, is continuing with solvent injection at its VAPEX pilot project at Carruthers and will update the progress of this project in the third quarter.

Baytex also experienced excellent success in its natural gas drilling program during the first quarter, with production added in every major property in its Northern and Plains districts. With average production in April of 74 million cubic feet per day, the first quarter capital program was able to completely replace production declines as well as the production sold in the asset divestiture program. A total of $25 million was expended by the Northern and Plains districts in the first quarter, yielding a capital efficiency of $15,000 per boe of production added during this period. The plan in the second quarter is to drill 20 wells targeting natural gas. However, inclement weather this spring may result in some of these wells being delayed to the third quarter, as the Company has yet to spud any wells so far in the second quarter.

Outlook

Capital expenditures for exploration and development in the second quarter of 2002 are budgeted at $35 million. At the current rates of production and commodity prices, this level of spending should be substantially below cash flow from operations. The Company's plan is to maintain its total 2002 exploration and development capital budget at $120 million. Baytex will endeavour to enhance its operation focus and efficiency through core area property acquisitions and non-core area property dispositions. In the meantime, any excess cash flow over capital spending will be used to reduce bank loans. If the Company does not complete any significant acquisitions, bank borrowings should be completely repaid by mid-summer in 2002.

The Canadian economy is experiencing a stronger recovery compared to that of the United States, resulting in the recent strengthening in our dollar. Baytex is well positioned to benefit from this as virtually all of its debt is denominated in U.S. dollars. Furthermore, interest obligations are pegged to U.S. LIBOR rates, which have remained low as the United States government carefully manages its fragile economic recovery. Commodity prices should remain favourable as heavy oil is now entering its high seasonal demand period and natural gas prices look to maintain their surprising strength with improving supply/demand expectations.

The fundamentals of Baytex are strong. Cash flow for the second quarter in 2002 should reach $1.00 per share under current production levels and commodity prices. The Company is excited by its potential to continue to deliver superior returns to its shareholders.

Management's Discussion and Analysis

Management's discussion and analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2002 and 2001 and the audited consolidated financial statements for the year ended December 31, 2001. Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Production. Light oil production for the first quarter of 2002 decreased by 2% to 3,818 bbl/d from 3,911 bbl/d for the same period in 2001 due to the sale of properties in December 2001 and January 2002. Heavy oil production decreased by 12% to 22,838 bbl/d for the first three months of 2002 from 25,970 bbl/d for the same period last year. The decline was the result of property sale and the curtailment of spending on heavy oil drilling and maintenance projects in the second half of 2001. Natural gas production increased by 28% to 73.7 mmcf/d for the first quarter of 2002 compared to 57.6 mmcf/d for the same period last year due to the OGY and Triumph acquisitions in the second quarter of 2001 and a successful drilling program.

Revenue. Revenue from light oil for the first quarter of 2002 decreased 30% from the corresponding period in 2001 due to a 29% decrease in wellhead prices and a 2% decrease in production. Revenue from heavy oil increased 30% due to a 48% increase in wellhead prices offset by a 12% decline in production. Natural gas revenue declined 40% due to a decrease of 53% in wellhead prices offset by a 28% increase in production.

	Three Months ended March 31			
	2002		2001	
	$000s	$/Unit	$000s	$/Unit
Oil Revenue (barrels)				
Light oil	9,476	27.58	13,605	38.65
Heavy oil	44,359	21.58	34,180	14.62
Derivative contracts gain (loss)	2,444	1.02	(3,955)	(1.47)
Total oil revenue	56,279	23.46	43,830	16.30
Natural gas revenue (mcf)	21,159	3.19	35,400	6.83
Derivative contracts gain	1,692	0.25	–	–
Total natural gas revenue	22,851	3.44	35,400	6.83
Total Revenue (boe @ 6:1)	79,130	22.57	79,230	22.30

Royalties. Total royalties decreased 24% to $11.8 million for the three months ended March 31, 2002 from $15.4 million for the same period last year. Total royalties for the first quarter of 2002 declined to 15.7% of sales compared to 18.6% of sales for the same period in 2001 due to the increase in heavy oil sales, which have a lower royalty rate in comparison to light oil and natural gas. Royalties as a percentage of sales by product were 17.0% for light oil, 12.7% for heavy oil and 21.6% for natural gas in the first quarter of 2002 compared to 19.9%, 9.1% and 27.1%, respectively, for the same period last year.

Operating Expenses. Operating expenses for the first quarter of 2002 increased 2% to $18.3 million from $17.8 million for the corresponding quarter last year. This increase is primarily attributable to the costs incurred to restore heavy oil wells that were shut-in during the fourth quarter of 2001. Operating expenses were $5.21 per boe for the first three months of 2002 compared to $5.02 per boe for the first quarter of 2001. For the first quarter of 2002, operating expenses were $6.25 per barrel of light oil, $5.91 per barrel of heavy oil and $0.60 per mcf of natural gas. Operating expenses by product for the same period last year were $5.96, $5.48 and $0.57, respectively.

General and Administrative Expenses. General and administrative expenses for the first three months of 2002 increased to $1.6 million from $1.1 million for the same quarter of 2001 as a result of increased staff levels associated with the Company's 2001 corporate acquisitions. On a per unit of production basis, these expenses increased from $0.32 per boe in 2001 to $0.45 per boe in 2002. In accordance with the full cost accounting policy, $1.6 million of expenses relating to exploration and development activities were capitalized in the first quarter of 2002 compared to $1.1 million during the same period in 2001.

Interest Expenses. Interest expenses on long-term debt were unchanged at $5.4 million for the first quarter of 2002 and 2001. While average debt levels were higher in the first quarter of 2002, interest rates on the Company's senior secured notes and senior subordinated notes were reduced from 7.23% to 4.7% and 10.5% to 7.1%, respectively, as a result of the interest rate swaps that the Company negotiated in December 2001.

Depletion, Depreciation and Amortization. The provision for depletion, depreciation and amortization increased to $26.3 million for the first three months of 2002 compared to $24.9 million for the same quarter last year. On a unit of production basis, the current period provision was $7.49 per boe compared to $7.02 per boe in the same period last year. This increase was the result of the acquisitions of OGY and Triumph in the second quarter of 2001.

Site Restoration Costs. Site restoration costs of $0.8 million for the first quarter of 2002 represent a decrease from $1.0 million for the same quarter last year. On a unit of production basis, the provision for the first quarter of 2001 was $0.23 per boe compared to $0.29 per boe for the corresponding quarter of last year.

Foreign Exchange. Effective January 1, 2002, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") amended accounting standard with respect to foreign currency translation. The amended standard eliminates the practice to defer and amortize foreign exchange gains and losses on long-term monetary items. As a result, all foreign exchange gains and losses on long-term monetary items are now recognized in earnings based on the exchange rates at the end of the reporting periods. The amended standard also requires that prior year's comparative figures be restated to comply with the new standard.

The application of the new standard resulted in an unrealized foreign exchange loss of $0.2 million in the first quarter of 2002 compared to a $13.1 million loss in the first quarter of 2001. The 2002 loss is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.6275 at March 31, 2002 compared to 0.6279 at December 31, 2001. The 2001 loss is based on the translation of the U.S. dollar denominated senior secured notes at 0.6340 at March 31, 2001 compared to 0.666 at December 31, 2000 along with the senior subordinated notes translated at 0.6340 at March 31, 2001 compared to 0.6582 on February 13, 2001 when the notes were issued.

Income Taxes. Current tax expenses were $2.0 million for the first quarter of 2002 compared to $1.8 million for the same quarter of 2001. The current tax expenses are comprised of $1.6 million of Saskatchewan Capital Tax and $0.4 million of Large Corporation Tax compared to $1.4 million and $0.4 million, respectively, for the same period in 2001.

Liquidity and Capital Resources. At March 31, 2002, total net debt (including working capital) was $383.7 million compared to $282.4 million at the end of the first quarter of 2001 and $379.1 million at December 31, 2001. The increase in total debt at the end of the first quarter of 2002 compared to 2001 was the result of the acquisitions that the company completed in 2001.

Effective January 1, 2002, the CICA's Emerging Issues Committee issued an abstract giving guidance on disclosure of callable debt obligations. Specifically, the abstract requires the classification of borrowings under a 364-day revolving credit facility as current liabilities. The Company's bank loans are structured under this type of credit facility and, as such, have been reclassified as current liabilities.

The senior secured notes are governed by certain financial covenants measured at the end of each fiscal quarter. The principal covenants are: (i) consolidated tangible net worth not to be less than $200 million, excluding accounting ceiling test write-down (such net worth was $481.9 million as at March 31, 2002); (ii) consolidated total debt not to exceed 300% of consolidated cash flow (such ratio was 190% as at March 31, 2002); and (iii) consolidated cash flow not to be less than 400% of consolidated interest expense (such ratio was 549% as at March 31, 2002). The senior subordinated notes are due February 2011 and do not require any financial covenant maintenance.

Capital Expenditures. Total exploration and development expenditures decreased to $40.0 million for the first quarter of 2002 compared to $44.8 million for the same period in 2001. The Company's total capital expenditures for these periods are summarized as follows:

	Three Months ended March 31	
	2002	2001
	($000s)	
Land	2,233	1,619
Seismic	2,030	3,068
Drilling and completions	25,709	22,297
Equipment	8,070	15,856
Other	1,949	1,961
Total exploration and development	39,991	44,801
Property acquisitions	690	623
Property dispositions	(47,053)	(918)
Net capital expenditures	(6,372)	44,506

Conference Call

A conference call has been scheduled for Tuesday, May 14, 2002 at 2:00 p.m. Mountain Daylight Time (4:00 p.m. EDT) to discuss Baytex's 2002 first quarter operating and financial results. Participants from the Company will include Dale Shwed, President and CEO and Ray Chan, Senior Vice-President and CFO. A question and answer period will follow the management presentation. To participate in the conference, please contact the Conference Operator at 1:50 p.m. (MDT), ten minutes prior to the call.

Conference Operator Dial in Number: 1-888-793-1751

The replay will be available one hour after the conclusion of the conference call and will be accessible until Tuesday, May 28, 2002. Callers may dial 1-800-558-5253 and enter Access Code #20549482. The conference call will be archived on Baytex's website at www.baytex.ab.ca. starting on May 16.

Annual Meeting

Baytex Energy's Annual Meeting of Shareholders will be held on Tuesday, May 28, 2002 at 3:00 p.m. Mountain Daylight Time in the Alberta Room of the Fairmont Palliser Hotel, 133 – 9th Ave. S.W., Calgary, Alberta.

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow and debt levels. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Company's areas of operations; and other factors, many of which are beyond the control of the Company. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

Baytex is an intermediate oil and gas exploration and production company whose shares are traded on The Toronto Stock Exchange under the trading symbol "BTE".

Financial statements for the three months ended March 31, 2002 are attached.

FOR DETAILED INFORMATION, PLEASE CONTACT:

Dale Shwed, President and C.E.O. Telephone: (403) 750-1241
Ray Chan, Senior Vice-President and C.F.O. Telephone: (403) 267-0715

Website: www.baytex.ab.ca

Baytex Energy Ltd.
Consolidated Balance Sheets
(Unaudited - thousands)

	March 31, 2002	*December 31, 2001* (restated – note 2)
Assets		
Current assets		
Accounts receivable	**$ 45,718**	$ 44,300
Properties held for sale	**-**	46,895
	45,718	91,195
Deferred financing charges	**8,414**	8,674
Petroleum and natural gas properties	**881,232**	867,177
	$ 935,364	$ 967,046
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 76,973**	$ 64,334
Current portion of long-term debt (note 3)	**22,179**	75,820
	99,152	140,154
Long-term debt (note 3)	**330,249**	330,102
Deferred revenue	**14,085**	18,694
Provision for future site restoration costs	**21,337**	20,541
Future income taxes	**152,023**	146,446
	616,846	655,937
Shareholders' Equity		
Share capital (note 4)	**394,839**	394,734
Deficit	**(76,321)**	(83,625)
	318,518	311,109
	$ 935,364	$ 967,046

Baytex Energy Ltd.
Consolidated Statements of Operations and Retained Earnings and Deficit
(Unaudited - thousands, except per share data)

	Three Months Ended March 31, 2002	2001 (restated – note 2)
Revenue		
Petroleum and natural gas sales	**$ 79,130**	$ 79,230
Royalties	**(11,782)**	(15,433)
	67,348	63,797
Expenses		
Operating	**18,271**	17,845
General and administrative	**1,587**	1,122
Interest on long-term debt	**5,370**	5,373
Foreign exchange (note 2)	**186**	13,115
Depletion, depreciation and amortization	**26,262**	24,943
Site restoration costs	**796**	1,024
	52,472	63,422
Income before income taxes	**14,876**	375
Income taxes		
Current	**1,995**	1,840
Future	**5,577**	228
	7,572	2,068
Net income (loss)	**7,304**	(1,693)
Retained earnings (deficit), beginning of period, as previously reported	**(75,954)**	52,555
Accounting policy change (note 2)	**(7,671)**	927
Retained earnings (deficit), beginning of period, as restated	**(83,625)**	53,482
Retained earnings (deficit), end of period	**$ (76,321)**	$ 51,789
Net income (loss) per share		
Basic	**$ 0.14**	$ (0.04)
Diluted	**$ 0.14**	$ (0.04)

Baytex Energy Ltd.
Consolidated Statements of Cash Flows
(Unaudited - thousands, except per share data)

	Three Months Ended March 31, 2002	2001
Cash provided by (used in):		
Operating activities		
Net income (loss)	**$ 7,304**	$ (1,693)
Items not affecting cash:		
Site restoration costs	**796**	1,024
Foreign exchange	**186**	13,115
Depletion, depreciation and amortization	**26,262**	24,943
Future income taxes	**5,577**	228
Cash flow from operations	**40,125**	37,617
Change in non-cash working capital	**(15,318)**	(6,102)
Deferred revenue	**(4,609)**	-
	20,198	31,515
Financing activities		
Issue of senior subordinated term notes	**-**	227,895
Increase (decrease) in bank loan	**(51,679)**	(125,755)
Increase in deferred financing charges	**-**	(8,122)
Issue of shares (net of issue expenses)	**105**	1,199
	(51,574)	95,217
Investing activities		
Petroleum and natural gas property expenditures	**(40,681)**	(45,424)
Disposal of petroleum and natural gas properties	**47,053**	918
Decrease in materials and supplies	**465**	736
Properties held for sale	**(46,895)**	-
Change in non-cash working capital	**71,434**	88
	31,376	(43,682)
Change in cash	**-**	83,050
Cash, beginning of period	**-**	-
Cash, end of period	**$ -**	$ 83,050
Cash flow from operations per share		
Basic	**$ 0.77**	$ 0.82
Diluted	**$ 0.76**	$ 0.80

Notes to the Consolidated Financial Statements
Three Months Ended March 31, 2002 and 2001
(Unaudited)

1. Accounting Policies

The interim consolidated financial statements of Baytex Energy Ltd. (the "Company") 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 of the Company as at December 31, 2001, except as described in note 2. The interim consolidated financial statements contain disclosures, which are supplemental to the Company's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2001.

2. Change in Accounting Policy

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants (CICA) amended accounting standard with respect to accounting 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 recognized in income. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item. The impact of the amended standard on current quarters' results was to decrease net income by $186,000 and increase the opening deficit by $7.7 million representing the cumulative effect of deferred foreign exchange losses at January 1, 2002.

The impact on the comparative balances was a decrease in unrealized foreign exchange loss at December 31, 2001 of $13.7 million, an increase in foreign exchange expense of $13.1 million, a decrease in net income of $7.2 million and an increase in opening retained earnings of $0.9 million.

3. Long-term Debt

(thousands)	March 31, 2002	December 31, 2001
Bank loan	$ 22,179	$ 73,820
Senior secured term notes (US$57,000,000)	90,830	90,778
Senior subordinated term notes (US$150,000,000)	239,025	238,890
Other long-term debt	394	2,434
	352,428	405,922
Less: current portion	22,179	75,820
	$ 330,249	$ 330,102

Effective January 1, 2002, the Company has classified borrowing under its bank facilities as current liability as required by new guidance under the CICA's Emerging Issues Committee Abstract 122. The bank loan at December 31, 2001 has been reclassified to conform with current presentation.

Bank loan

At March 31, 2002, the bank facilities were limited to a total commitment under the facilities of $85 million and a borrowing base of $175 million.

4. Share Capital

The Company has an unlimited number of common shares in its authorized share capital.

Issued and Outstanding:
Common shares – (thousands)

	# of shares	Amount
Balance – January 1, 2002	52,008	$ 394,734
Exercise of stock options	28	105
Balance – March 31, 2002	52,036	$ 394,839

Stock options – (thousands)	# of options	Weighted average exercise price
Balance – January 1, 2002	4,468	$ 6.19
Granted	19	5.50
Exercised	(28)	3.80
Cancelled	(42)	4.72
Balance – March 31, 2002	4,417	$ 6.21
Exercisable – March 31, 2002	1,799	$ 6.13

The Company accounts for its stock options using the intrinsic-value method. Under the intrinsic value method, compensation costs are not required to be recognized in the financial statements for stock options granted at market value. Had compensation costs for the Company's stock option plan been determined based on the fair-value method at the dates of grants under the plan after January 1, 2002, the Company's pro-forma net income and earnings per share would be the same as those reported.

5. Derivative Contracts

For the year 2003, the Company has entered into oil price collar contracts for 10,000 bbl/d between WTI US$20.00 and an average US$26.56.

6. Comparative Figures

Certain comparative figures have been reclassified to conform to current year's presentation.

BAYTEX ENERGY LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2001

MAY 14, 2002

TABLE OF CONTENTS

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"M$"	thousands of Canadian dollars	**"mmcf"**	1,000,000 cubic feet
"MM$"	millions of Canadian dollars	**"bcf"**	1,000,000,000 cubic feet
"bbl"	barrels	**"mcf/d"**	one thousand cubic feet per day
"mbbl"	1,000 barrels	**"mcfe"**	1,000 cubic feet equivalent
"mmbbl"	1,000,000 barrels	**"mmcf/d"**	one million cubic feet per day
"bbl/d"	barrels per day	**"boe"**	barrels of oil equivalent
"stb"	stock tank barrels	**"mboe"**	1,000 barrels of oil equivalent
"NGL"	natural gas liquids	**"boe/d"**	barrels of oil equivalent per day
"mcf"	1,000 cubic feet	**"m3"**	cubic metre

Note: for the purposes of this document, 6 mcf of natural gas and 1 bbl of NGL each equal 1 bbl of oil, such conversion not being based on either price or energy content.

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"ABCA" means the Business Corporations Act, S.A. 1981, c. B-15, together with any amendments thereto and all regulations promulgated thereunder;

"API" means American Petroleum Institute;

"ARTC" means the Alberta royalty tax credit;

"Baytex" or the **"Company"** means Baytex Energy Ltd.;

"Common Shares" means common shares in the share capital of the Company;

"**GAAP**" means Canadian generally accepted accounting principles;

"Outtrim Report" means the independent engineering evaluation of Baytex's crude oil and natural gas reserves prepared by Outtrim Szabo Associates Ltd. ("Outtrim"), independent oil and gas reservoir engineers of Calgary, Alberta, dated March 1, 2002 and effective December 31, 2001; and

"TSE" means The Toronto Stock Exchange.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENT

Baytex Energy Ltd. ("Baytex" or the "Company") is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intends," "plans," "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Among the key factors that have a direct bearing on the Company's results of operation are the nature of the Company's involvement in the business of exploration, development and production of oil and natural gas reserves, fluctuations in pricing of oil and natural gas, fluctuations in interest rates and the fluctuation of the exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under "Management's Discussion and Analysis", incorporated by reference from the Company's 2001 Annual Report and elsewhere in this Annual Information Form.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, investors should not place undue reliance on any such forward-looking statements. Further, any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

THE COMPANY

Incorporation and Organization

The Company was incorporated under the ABCA on June 3, 1993. On August 5, 1993, the Company filed Articles of Amendment to delete the private company restrictions thereunder. On October 13, 1993, Articles of Amendment were filed to amend the Company's capital structure to create Class A Shares and Class B Non-Voting Shares. On October 21, 1997, the Company filed Articles of Amalgamation to amalgamate with its wholly owned subsidiary, Dorset Exploration Ltd. On May 28, 1999, the Company filed Articles of Amendment to eliminate the Class B Shares of the Company and to change the designation of the Class A shares in the share capital of the Company from "Class A Shares" to "Common Shares". On January 1, 2002, the Company filed Articles of Amalgamation to amalgamate with its wholly owned subsidiaries OGY Petroleums Ltd. and Triumph Energy Corporation.

Baytex has two active wholly-owned subsidiaries, Baytex Exploration Ltd. (formerly Bellator Exploration Inc.) and Baytex Resources Ltd. (formerly Aquilo Energy Inc.), both of which were incorporated pursuant to the provisions of the ABCA. In addition, on January 1, 2001, Baytex formed a general partnership named Baytex Energy Partnership (the "Baytex Partnership") with both of these subsidiaries. Each partner has contributed substantially all of its producing properties to the Baytex Partnership.

The Company's principal office is located at Suite 2200, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 2V7. Its registered office is located at Suite 1400, 350 - 7th Ave. S.W., Calgary, Alberta, T2P 3N9.

General Development of the Company

Prior to 1997, Baytex carried on its oil and gas operations primarily in a number of areas in east central Alberta with the focus on natural gas exploration and development.

In October of 1997, the Company acquired all of the issued and outstanding common shares of Dorset Exploration Ltd. ("Dorset"), a public oil and gas company, the shares of which were listed on the TSE. The total consideration paid by Baytex for Dorset was 15,573,175 Baytex common shares. The operations of Dorset included heavy oil production in west central Saskatchewan and light oil and natural gas in central Alberta.

Subsequent to the Baytex/Dorset merger, the Company focused its attention towards light oil and natural gas development in central and north central Alberta along with development of its existing heavy oil assets in western Saskatchewan.

In May of 2000, Baytex acquired all of the issued and outstanding shares of Bellator Exploration Inc. ("Bellator"), a public oil and gas company, the shares of which were listed on the TSE. The total consideration paid by Baytex for Bellator was $39,933,000 cash and 8,785,287 Baytex common shares. The operations of Bellator concentrated on conventional heavy oil production in western Saskatchewan. Throughout the remainder of 2000, the Company focused its attention on the development of its new heavy oil assets drilling in excess of 270 heavy oil wells.

In May 2001, Baytex acquired all of the issued and outstanding shares of OGY Petroleums Ltd. ("OGY"), a public oil and gas company, the shares of which were listed on the TSE. The total consideration paid by Baytex for OGY was $50,683,000 cash and 1,169,481 Baytex common shares. The operations of OGY concentrated on light oil and natural gas in central Alberta.

Also in May 2001, Baytex acquired all of the issued and outstanding shares of Triumph Energy Corporation ("Triumph"), a public oil and gas company, the shares of which were listed on the TSE. The total consideration paid for Triumph was $82,337,000 cash and 4,949,245 Baytex common shares. The operations of Triumph focused on the exploration and development of natural gas in Central Alberta and light oil and natural gas in East Central and Southern Alberta.

The Company also acquired two additional heavy oil properties in the second quarter of 2001 for $40,500,000. These acquisitions included operations in the Cold Lake area of Alberta and additional property in western Saskatchewan.

BUSINESS OF THE COMPANY

During 2001, the Company further focused our operations in our main geographical regions by reorganizing our technical staff into three districts. These districts are focused on taking advantage of the vast amount of technical and operating information that we have in our core areas to evaluate potential prospects in these areas, identify strategic acquisitions in the areas and to develop and operate our existing properties in an efficient and low-cost manner.

The following table sets forth the Company's average daily oil and natural gas production by district for the years ended December 31, 2001 and 2000.

	Year ended December 31,			
	2001		2000	
	Oil and NGL (bbl/d)	Natural Gas (mmcf/d)	Oil and NGL (bbl/d)	Natural Gas (mmcf/d)
Heavy Oil District	26,901	11.5	20,353	8.8
Plains District	3,721	35.5	1,985	22.4
Northern District	1,063	23.8	1,774	26.5
Total	31,685	70.8	24,112	57.5

Heavy Oil District

Our Heavy Oil District makes up the largest component of Baytex's current production and reserve base. In 2001, Baytex produced 26,533 bbl/d of heavy oil, 368 bbl/d of light oil and 11.5 mmcf/d of natural gas from this district. It includes operations in our main areas at Tangleflags, Lashburn, Carruthers, and Poundmaker in Saskatchewan and Cold Lake in Alberta.

Our heavy oil operations consist mainly of cold conventional production from the Cummings, Colony, McLaren, Waseca, Sparky and Lloydminster formations. Production focuses on vertical and slant wells using progressive cavity pumping to generate initially large volumes of sand and oil. The removal of sand from the reservoir creates "worm holes" that leads to increased oil production. Production from these wells usually averages between 40 and 100 bbl/d of sour, lower gravity crude ranging from 12 to 18 API. Once production is in the tank, oil is separated from sand and then trucked or pipelined to markets in Canada and the United States for upgrading into a lighter grade of crude or refined into petroleum products.

In 2001, the Company drilled 58 successful heavy oil wells throughout our operating areas in west central Saskatchewan and in our newly acquired area at Cold Lake, Alberta. Heavy oil drilling was curtailed in the latter part of 2001 as oil prices declined significantly and heavy oil differentials remained at their widest levels ever. The Company also reduced spending on regular well maintenance and shut-in approximately 3,000 bbl/d of heavy oil production as a result of the poor economics.

The year 2002 has brought a brighter outlook for our Heavy Oil District. Oil prices have strengthened throughout the first quarter with WTI reaching US$25.00/bbl by mid-March. Heavy oil differentials have also dramatically improved from US$10.00/bbl for Lloyd Blend at Hardisty in the fourth quarter of 2001 to around US$5.00 in March 2002. With the economics for heavy oil improving, the Company has planned for the drilling of 110 heavy oil wells in 2002. This drilling will be focused in our Cold Lake and Tangleflags areas targeting multi-zone conventional heavy oil production. Since the beginning of January, we have also been reactivating the production that had been shut-in during the fourth quarter of last year.

Baytex continues to pursue new heavy oil opportunities and is continually adding to its drilling inventory to underpin future production growth. We are also actively participating in a research and development project for enhanced recovery through our VAPEX pilot project. This vapour extraction process, if successful, could significantly increase the Company's heavy oil production and reserves recovery factors from existing oil pools.

Plains District

The Plains District is the Company's largest natural gas producing area. Average production in 2001 included 35.5 mmcf/d of natural gas and 3,721 bbl/d of light oil and natural gas liquids. Natural gas production is from several areas across central Alberta, the most significant ones being Bon Accord, Ferrier, Leahurst, O'Chiese and Richdale. The district's current light oil production comes from Sounding Lake, a property acquired in the OGY transaction, and from Bon Accord in central Alberta.

The Plains District realized the largest benefit from our 2001 corporate acquisitions. The acquisition of OGY added significant natural gas development potential in the Richdale and Viking areas. The Richdale area, with its Second White Specks and Lower Manville gas pools, complements our existing assets at Leahurst/Donalda. Subsequent to this acquisition, the Company drilled 15 successful Second White Specks gas wells in the area. Current production from the Richdale area is in excess of 6.8 mmcf/d. We plan to drill additional Second White Specks wells in the area over the next year as well as several lower Manville targets.

At Viking, Baytex drilled five successful lower Mannville and Basal Belly River gas wells in 2001 with production increasing to 5.1 mmcf/d currently. In the first quarter of 2002, we conducted a 2D seismic program to evaluate the southern portion of our holdings in the area. The Company holds in excess of 25,000 acres of undeveloped land in the Viking area.

The acquisition of Triumph in May added significant production and development potential in the Ferrier area where the drilling targets are long life, multi-zone liquids-rich natural gas reserves. Subsequent to the acquisition, the Company drilled seven natural gas wells in this area in 2001. These wells are capable of production from the Cretaceous Ostracod, Ellerslie and Rock Creek formations. Current production from this area includes 10.0 mmcf/d of natural gas and 600 bbl/d of natural gas liquids. In 2002, we plan to drill 10 to 12 development wells in this area.

We also acquired operations in the O'Chiese area through the Triumph transaction, where the target is natural gas from the Cretaceous Ostracod formation. We drilled two wells in 2001 resulting in one oil well and one natural gas well. To date in 2002, two additional wells have been drilled adding two natural gas wells. Natural gas wells in this area typically result in stabilized production between 1.0 and 2.0 mmcf/d.

We are focused on improving operational efficiencies within the new areas that the Company acquired in 2001. Efforts continue to develop new plays over the District's 273,000 net acres of undeveloped land with particular focus on opportunities within and adjacent to our existing core areas.

Northern District

Our Northern District is situated in northwestern Alberta and northeastern B.C. and includes all of the Company's operating areas north of Township 50 and west of the fifth meridian. This area holds Baytex's greatest potential for high impact natural gas exploration success. While the area does not have a large percentage of the Company's current producing assets, this District has over 840,000 acres of land including 588,800 acres of undeveloped land with an average working interest of 85 percent.

Production from the area in 2001 averaged 23.8 mmcf/d of natural gas and 1,063 bbl/d of light oil. Light oil production in the district comes mainly from the Slave Point and Granite Wash formations in the Red Earth area, where two successful oil wells were drilled in 2001 and one oil well was drilled in the first quarter of 2002.

Natural gas production in the Northern District is produced mainly from the Bluesky formation in the Goodfish/Lafond and Darwin/Nina areas. Baytex drilled seven gas wells in 2001 and an additional eight gas wells in the first quarter of 2002. We continually evaluate new prospects in these areas which had a low average operating cost of $0.43/mcf in 2001 due to our ownership of an extensive pipeline infrastructure and natural gas processing plants.

Baytex conducts the majority of its high impact exploration activities in the Northern District. At Dawson/Tangent, we drilled two Cretaceous natural gas wells in the first quarter of 2002. These wells are planned to be tied-in and on production early in the second quarter and should add an additional 3.5 mmcf/d of natural gas production to the Company by the end of the second quarter. We are conducting a 2D seismic program in the area to identify additional locations to be drilled in the second half of 2002. Also at Dawson/Tangent, a 3D seismic program is being conducted to identify oil targets in the Slave Point formation. These targets can result in wells that have up to 500,000 bbl of recoverable reserves and produce at rates ranging from 250 bbl/d to 1,000 bbl/d.

Exploration is also continuing on Baytex's lands in the Hamburg/Chinchaga area. In the first quarter of 2002, a natural gas well was drilled at Chinchaga into the Slave Point formation. This well is currently being tested and may result in follow-up locations to be drilled in the latter half of 2002. Wells in this area are capable of producing up to 80 mmcf/d and may have recoverable reserves of over 100 bcf.

The Company holds 53,000 net undeveloped acres at Petitot in northwest Alberta where it is exploring for Slave Point natural gas targets. These wells can yield reserves up to 15 bcf and produce at rates up to 15 mmcf/d. Current plans are to drill our first exploration well in this area during the 2002/2003 winter season.

LAND HOLDINGS

The undeveloped land holdings of the Company as at December 31, 2001, are set forth in the following table:

	Undeveloped	
	Gross(1)	Net(2)
Alberta	1,056,273	864,054
Saskatchewan	251,686	223,408
British Columbia	77,533	52,343
Total	1,385,492	1,139,805

Notes:

(1) "Gross" acres means the total number of acres in which the Company has an interest.

(2) "Net" acres refers to the aggregate of the percentage interests of the Company in the gross acres.

OIL AND GAS WELLS

The following table summarizes Baytex's interests as at December 31, 2001 in oil and natural gas wells which are producing or which are considered capable of production. All significant non-producing natural gas wells are within 10 kilometres of an existing pipeline.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Alberta	333	241	403	282	151	112	248	182
Saskatchewan	886	819	46	42	292	291	31	27
British Columbia	-	-	-	-	-	-	5	5
Total	1,219	1,060	449	324	443	403	284	214

Notes:

(1) "Gross" wells refers to all wells in which Baytex owns a working interest.

(2) "Net" wells refers to the aggregate of the percentage working interests of Baytex in the gross wells, before the deduction of royalties.

(3) All significant non-producing natural gas wells are within six miles of an existing pipeline.

OIL AND GAS RESERVES

Outtrim has prepared the Outtrim Report evaluating the proved and probable additional crude oil, NGL and natural gas reserves of Baytex's properties as of December 31, 2001. In preparing its report, Outtrim obtained basic information from Baytex, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required by Outtrim was obtained from public records, other operators and from Outtrim's non-confidential files. Outtrim did not independently verify the factual information that Baytex provided to it or that it obtained from other sources. Outtrim did not conduct a field inspection.

The following tables, based on the Outtrim Report, show the estimated share as at the dates indicated of Baytex's crude oil, natural gas and NGL reserves and the present value of estimated future cash flow for these reserves using escalated and constant prices and costs as indicated. **The present worth of estimated future cash flow is stated after provisions for estimated future capital expenditures and abandonment costs for the wells net of salvage value and prior to provision for income taxes.**

CRUDE OIL AND NATURAL GAS RESERVES AND PRESENT WORTH OF ESTIMATED FUTURE CASH FLOW

ESCALATED DOLLAR ECONOMICS

	Remaining Reserves						Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
	Crude Oil		Natural Gas		NGLs					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	stb	stb	mmcf	mmcf	bbl	bbl	M$	M$	M$	M$
Proved Developed										
Producing	30,901,330	27,777,580	91,605	74,175	1,043,017	669,039	608,890	446,084	397,968	361,097
Non-Producing	38,930,790	33,574,476	30,731	24,152	330,228	217,384	482,389	245,032	193,899	159,223
Proved Undeveloped	38,614,640	35,585,496	12,317	9,495	400,854	255,515	431,926	232,986	182,069	145,915
Total Proved	108,446,760	96,937,552	134,653	107,822	1,774,099	1,141,938	1,523,205	924,102	773,936	666,235
Probable Additional	51,613,832	46,036,224	42,767	33,983	720,281	456,705	730,324	354,566	270,937	214,324
Total Before Risk	160,060,592	142,973,776	177,420	141,805	2,494,380	1,598,643	2,253,529	1,278,668	1,044,873	880,559
Reduction Due to Risk	(25,806,916)	(23,018,112)	(21,383)	(16,991)	(360,140)	(228,352)	(365,162)	(177,283)	(135,468)	(107,162)
Total After Risk	134,253,676	119,955,664	156,037	124,814	2,134,240	1,370,291	1,888,367	1,101,385	909,405	773,397

CONSTANT DOLLAR ECONOMICS

	Remaining Reserves						Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
	Crude Oil		Natural Gas		NGLs					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	stb	stb	mmcf	mmcf	bbl	bbl	M$	M$	M$	M$
Proved Developed										
Producing	29,592,786	26,598,204	91,156	72,760	1,040,254	668,213	439,620	328,615	295,414	269,779
Non-Producing	35,793,726	31,292,820	30,772	23,873	330,854	217,953	220,117	126,066	102,892	86,383
Proved Undeveloped	38,189,728	35,568,624	12,299	9,138	399,944	255,379	188,820	99,174	75,245	58,059
Total Proved	103,576,240	93,459,648	134,227	105,771	1,771,052	1,141,545	848,557	553,855	473,551	414,221
Probable Additional	49,914,848	45,051,552	42,655	33,266	719,810	457,942	377,447	192,280	147,751	116,789
Total Before Risk	153,491,088	138,511,220	176,882	139,037	2,490,862	1,599,487	1,226,004	746,135	621,302	531,010
Reduction Due to Risk	(24,957,424)	(22,525,776)	(21,327)	(16,633)	(359,905)	(228,971)	(188,723)	(96,140)	(73,875)	(58,394)
Total After Risk	128,533,644	115,985,424	155,555	122,404	2,130,957	1,370,516	1,037,281	649,995	547,427	472,616

Notes:

(1) **"Gross"** reserves are defined as those accruing to the Company before deduction of all royalties and interests owned by others.
"Net" reserves are defined as those accruing to the Company after deduction of all royalties and interests owned by others.

(2) Probable additional cash flows presented in the Outtrim Report are prepared at full value assuming that the quantities and values of the forecast production are unrisked. For the purpose of determining the values presented in these tables, a risk factor of 50% has been applied to the probable additional reserves and cash flows.

(3) **"Proved Reserves"** are those reserves estimated as recoverable under current technology and anticipated economic conditions for the escalated dollar economics and existing economic conditions for the constant dollar economics, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economical and technically successful in the subject reservoir.

(a) **"Proved Producing Reserves"** are those developed reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner rather than the lack of markets or some other reasons. An illustration of such a situation is where a well or zone is capable but is shut in because its deliverability is not required to meet contract commitments.

(b) **"Proved Non-Producing Reserves"** are those developed reserves that are not currently producing either due to lack of facilities and/or markets.

(c) **"Proved Undeveloped Reserves"** are proved reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreages are limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled.

(4) **"Probable Additional Reserves"** are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and anticipated economic conditions for the escalated dollar economics and existing economic conditions for the constant dollar economics, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery process which can be reasonably expected to be instituted in the future.

(5) **Price Forecast**

OUTRIM SZABO ASSOCIATES LTD. PRICE FORECAST
EFFECTIVE DATE DECEMBER 31, 2001

Oil Prices

YEAR	OIL FIELD COSTS INFLATION %	EXCHANGE $CDN/$US	WTI @ Cushing $US/bbl	EDM. OIL PRICE D2S2 $/bbl	HEAVY OIL 25 API HARDISTY $bbl	HEAVY OIL 12 API HARDISTY $bbl
2002	0.0	0.640	20.50	31.13	22.63	16.13
2003	1.5	0.650	20.81	31.09	23.59	18.59
2004	1.5	0.660	21.12	31.05	25.05	20.55
2005	1.5	0.670	21.44	31.02	25.52	21.52
2006	1.5	0.670	21.76	31.48	25.98	21.98
2007	1.5	0.670	22.08	31.96	26.46	22.46
2008	1.5	0.670	22.42	32.44	26.94	22.94
2009	1.5	0.670	22.75	32.92	27.42	23.42
2010	1.5	0.670	23.09	33.42	27.92	23.92
2011	1.5	0.670	23.44	33.92	28.42	24.42

escalated oil and NGL prices at 1.5% per year thereafter

Natural Gas Prices

YEAR	TCGSL $/mcf	PAN ALBERTA $/mcf	PRO GAS $/mcf	DIRECT $/mcf	SPOT $/mcf
2002	3.92	3.34	4.04	3.97	4.12
2003	4.14	3.62	4.14	4.09	4.39
2004	4.25	3.91	4.25	4.22	4.43
2005	4.36	4.19	4.36	4.34	4.42
2006	4.47	4.47	4.47	4.47	4.47
2007	4.55	4.55	4.55	4.55	4.55
2008	4.64	4.64	4.64	4.64	4.64
2009	4.70	4.70	4.70	4.70	4.70
2010	4.76	4.76	4.76	4.76	4.76
2011	4.82	4.82	4.82	4.82	4.82

escalated oil and NGL prices at 1.5% per year thereafter

(6) Product prices in the constant price evaluations are based on actual prices received for oil and natural gas liquids and natural gas at December 31, 2001.

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the effective date of the Outtrim Report. In addition, operating and capital costs have not been increased on an inflationary basis.

(7) ARTC varies from a maximum of 75% of $2.0 million when the oil price is below US $15 per barrel to a minimum of 25% of $2.0 million when the oil price is above US$30 per barrel. For the cash flow projection, the ARTC program was assumed to stay in place for a period of 10 years.

(8) Outtrim estimates the total capital costs net to Baytex to achieve the estimated future net proved and probable production revenues set out in the Outtrim Report, based on escalating cost assumptions, to be $211.2 million (discounted at 10%).

Outtrim estimates the total capital costs net to Baytex to achieve the estimated future net proved and probable production revenues set out in the Outtrim Report, based on constant cost assumptions, to be $205.5 million (discounted at 10%).

(9) Cash flow is income derived from the sale of net reserves, less all capital costs, production taxes, and operating costs and before provision for income taxes and administrative overhead costs.

RECONCILIATION OF RESERVES

A reconciliation of the Company's oil and gas reserves for the two-year period ended December 31, 2001 is set out below:

	Crude Oil and NGLS *(mmbls)*			Natural Gas *(mmcf)*		
	Proved	Probable	Total	Proved	Probable	Total
December 31, 1999	56,420	37,055	93,475	103,947	47,604	151,551
Discoveries and extensions	17,684	2,108	19,792	9,727	3,074	12,801
Acquisitions	37,700	10,905	48,605	10,767	-	10,767
Dispositions	(213)	(109)	(322)	(3,735)	(4,650)	(8,385)
Revisions of prior estimates	2,256	(1,921)	335	(1,556)	(15,826)	(17,382)
Production	(8,825)	-	(8,825)	(21,102)	-	(21,102)
December 31, 2000	105,022	48,038	153,060	98,048	30,202	128,250
Discoveries and extensions	11,049	4,054	15,103	19,705	3,421	23,126
Acquisitions	12,832	7,241	20,073	61,162	18,050	79,212
Dispositions	(7,593)	(5,809)	(13,402)	(6,527)	(1,725)	(8,252)
Revisions of prior estimates	477	(1,190)	(713)	(11,887)	(7,181)	(19,068)
Production	(11,566)	-	(11,566)	(25,848)	-	(25,848)
December 31, 2001	110,221	52,334	162,555	134,653	42,767	177,420

DRILLING ACTIVITY

The following table summarizes the Company's drilling results for the years ended December 31, 2001 and 2000.

	Year ended December 31,			
	2001		2000	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Oil	63	58.2	267	263.9
Natural Gas	81	70.3	28	24.3
Service	3	2.4	4	4.0
Dry & Abandoned	32	28.7	23	20.4
Total	179	159.6	322	312.6

Notes:

(1) "Gross" wells refers to all wells in which the Company has either a working interest or a royalty interest.

(2) "Net" wells refers to the aggregate of the percentage working interests of the Company in the gross wells, before the deduction of royalties.

HISTORY

The following table shows the Company's average working interest sales volume before deduction of royalties payable to others, average netbacks received and net oil and gas capital expenditures incurred for each of the last eight fiscal quarters and the years then ended:

Average Daily Sales

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	Total
Light/medium crude oil and NGL (bbl/d)	3,911	4,782	6,077	5,808	5,152
Heavy crude oil (bbl/d)	25,970	26,545	29,078	24,528	26,533
Total crude oil and NGL (bbl/d)	29,881	31,327	35,155	30,336	31,685
Natural gas (mmcf/d)	57.6	71.3	78.2	75.9	70.8

	Three Months Ended				
	Mar 31, 2000	June 30, 2000	Sept 30, 2000	Dec 31, 2000	Total
Light/medium crude oil and NGL (bbl/d)	4,125	4,087	3,970	4,245	4,107
Heavy crude oil (bbl/d)	10,326	17,396	25,260	26,904	20,005
Total crude oil and NGL (bbl/d)	14,451	21,483	29,230	31,149	24,112
Natural gas (mmcf/d)	58.4	59.2	58.4	54.7	57.7

Natural Gas Netbacks ($ per mcf)

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	Total
Sales revenue	6.83	5.11	3.35	3.09	4.42
Royalties	(1.85)	(1.48)	(0.75)	(0.58)	(1.11)
Operating costs (1)	(0.57)	(0.56)	(0.70)	(0.70)	(0.64)
Netback	4.41	3.07	1.90	1.81	2.67

	Three Months Ended				
	Mar 31, 2000	June 30, 2000	Sept 30, 2000	Dec 31, 2000	Total
Sales revenue	2.85	3.57	3.96	5.82	4.01
Royalties	(0.56)	(0.59)	(1.11)	(1.50)	(0.91)
Operating costs (1)	(0.41)	(0.41)	(0.53)	(0.54)	(0.47)
Netback	1.88	2.57	2.32	3.78	2.63

Note:

(1) Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.

Crude Oil and NGL Netbacks ($ per bbl)

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	Total
Sales revenue (1)	16.09	18.12	23.90	15.49	18.63
Royalties (2)	(2.17)	(2.31)	(3.82)	(1.61)	(2.53)
Operating costs (3)	(5.55)	(6.15)	(5.72)	(5.74)	(5.79)
Netback	8.38	9.66	14.36	8.14	10.31
Crude oil prices					
Light/medium crude oil and NGL	36.97	35.73	33.52	27.04	32.83
Heavy crude oil	12.95	14.94	21.89	12.76	15.87

	Three Months Ended				
	Mar 31, 2000	June 30, 2000	Sept 30, 2000	Dec 31, 2000	Total
Sales revenue (1)	26.85	24.90	26.69	16.00	22.85
Royalties (2)	(3.76)	(4.12)	(4.09)	(2.49)	(3.53)
Operating costs (3)	(4.72)	(4.93)	(4.80)	(5.27)	(4.97)
Netback	18.37	15.85	17.80	8.24	14.35
Crude oil prices					
Light/medium crude oil and NGL	32.64	30.61	34.73	38.64	34.20
Heavy crude oil	24.54	23.55	25.44	12.40	20.51

Note:

(1) After reduction for hedging costs.

(2) After inclusion of ARTC.

(3) Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.

Net Oil and Gas Capital Expenditures ($000's)

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	Total
Exploration and land (including drilling)	14,154	11,981	6,968	3,453	36,556
Development	28,686	24,343	24,103	14,145	91,547
Other	1,961	2,080	2,137	1,840	8,018
Property Acquisitions, net of dispositions	(295)	291,270	705	(51,716)	239,964
	44,506	329,674	33,913	32,278	376,085

	Three Months Ended				
	Mar 31, 2000	June 30, 2000	Sept 30, 2000	Dec 31, 2000	Total
Exploration and land (including drilling)	11,564	10,014	7,017	11,279	39,874
Development	20,487	34,946	38,526	30,941	124,900
Other	930	1,206	2,018	1,859	6,013
Property Acquisitions, net of dispositions	(290)	203,900	11,200	(740)	214,070
	32,691	250,066	58,761	43,339	384,857

FUTURE COMMITMENTS

At December 31, 2001, the Company had in place contracts for the following:

	Period	Volume	Price	Index
Oil				
Price collar	Calendar 2002	10,000 bbl/d	US$20.00 – $25.00	WTI
Fixed price	Calendar 2002	1,000 bbl/d	US$21.10	WTI
	Calendar 2002	1,500 bbl/d	US$21.09	WTI
Natural Gas				
Fixed price	January 2002 – October 2002	10,000 GJ/d	CAN$4.25	AECO
	January 2002 – October 2002	10,000 GJ/d	CAN$3.37	AECO
Price collar	January 2002 – October 2002	10,000 GJ/d	CAN$3.75 – $5.00	AECO
	January 2002 – October 2002	10,000 GJ/d	CAN$3.00 – $3.90	AECO

	Period	Principle	Rate
Interest rate swap	December 2001 to November 2004	US$57 million	3-month LIBOR plus 2.71%
	December 2001 to February 2006	US$150 million	3-month LIBOR plus 5.40%

	Period	Amount	Exchange Rate
Foreign currency swap	January 1998 to December 2005	US$315,000 per month	CAD/USD $1.4228

DIRECTORS AND OFFICERS OF BAYTEX

The name, municipality of residence and principal occupation of each of the directors and senior officers of Baytex are as follows:

Name and Municipality of Residence	Positions Held[5][6]	Principal Occupation During Last Five Years
John A. Brussa[1][2][4][5] Calgary, Alberta	Director	Partner, Burnet, Duckworth & Palmer, LLP Barristers and Solicitors
W.A. Blake Cassidy[1][2][5] Calgary, Alberta	Director	Retired Banker
Raymond T. Chan Calgary, Alberta	Senior Vice-President, Chief Financial Officer and Director	Senior Vice-President of Baytex since October, 1998; prior thereto Senior Vice-President and Chief Financial Officer of Tarragon Oil and Gas Limited
Frederic C. Coles[3][4][5] DeWinton, Alberta	Director	Independent Businessman since April 1, 2002; prior thereto Executive Chairman, Applied Terravision Systems Ltd.
Dennis L. Nerland[1][5] Calgary, Alberta	Director	Partner, Shea Nerland Calnan Barristers and Solicitors
Dale O. Shwed[2][3][8] Calgary, Alberta	President, Chief Executive Officer and Director	President of Baytex

Name and Municipality of Residence	Positions Held[5][6]	Principal Occupation During Last Five Years
Ralph W. Gibson Calgary, Alberta	Vice-President, Marketing	Vice-President, Marketing of Baytex since September, 2001; prior thereto Vice-President, Crude Oil of Canpet Energy Group Inc. since November 2000; prior thereto Vice-President, Marketing, Ranger Oil Limited since September 1997; and prior thereto Vice-President, Marketing, Elan Energy Inc.
Daniel B. Horner Calgary, Alberta	Vice-President, Land	Vice-President, Land of Baytex since January, 2000; prior thereto Land Manager and Solicitor of Baytex since March, 1999; prior thereto Solicitor and Senior Landman of Amber Energy Inc. (and its successor, AEC Oil & Gas) since December, 1997; prior thereto Corporate Solicitor of Norsk Hydro Canada Oil & Gas since August, 1997; prior thereto Corporate Solicitor and Senior Landman of Stampeder Exploration Ltd. since March, 1994
John G. Leach Calgary, Alberta	Vice-President, Finance and Administration	Vice-President, Finance and Administration of Baytex since October, 1998; and prior thereto Treasurer of Baytex since December, 1996
S. Dale McAuley Calgary, Alberta	Vice-President, Operations	Vice-President, Operations of Baytex since June, 1997; and prior thereto Engineering Manager of Baytex since February, 1995
Richard W. Naden Calgary, Alberta	Vice-President, Production	Vice-President, Production of Baytex since October, 1997; prior thereto Vice-President, Operations of Dorset Exploration Ltd.
Garry J. Wasylycia Calgary, Alberta	Vice-President, Exploration	Vice-President, Exploration of Baytex since July, 1998; and prior thereto Senior Geologist of Baytex since May, 1996
Shannon M. Gangl Calgary, Alberta	Secretary	Partner, Burnet, Duckworth & Palmer LLP, Barristers and Solicitors since January, 1999; prior thereto Associate, Burnet, Duckworth & Palmer LLP, Barristers and Solicitors

Note:

(1) Member of the Audit Committee.

(2) Member of the Compensation Committee.

(3) Member of the Environmental Management Committee.

(4) Member of the Corporate Governance Committee.

(5) Member of the Reserve Committee.

(6) The following individuals were initially appointed or elected directors of Baytex on the following dates: Mr. Shwed (June 3, 1993), Mr. Cassidy (February 8, 1994), Mr. Brussa (October 8, 1997), Mr. Coles (May 26, 1998) and Mr. Chan (October 5, 1998). Mr. Nerland was a director of Baytex from October, 1993 to October, 1997, when he resigned in connection with the business combination with Dorset. Mr. Nerland was re-elected as a director on May 26, 1998.

(7) The directors will hold office until the next annual meeting of holders of Common Shares or until their successor is duly elected or appointed, unless their office is earlier vacated in accordance with the Company's By-Laws.

(8) Mr. Shwed was a director of Echelon Energy Inc., a private company incorporated under the ABCA. In September of 1999, a receiver manager was appointed over the assets of Echelon.

As at April 30, 2002, the directors and senior officers of Baytex, as a group, beneficially owned, directly or indirectly, 681,232 Common Shares constituting approximately 1.3% of the issued and outstanding Common Shares.

PERSONNEL

As at December 31, 2001, Baytex had 145 employees.

DIVIDEND RECORD

Baytex has not declared or paid any dividends on its Common Shares since its incorporation, and does not foresee the declaration or payment of any dividends on the Common Shares in the near future. Any decision to pay dividends on the Common Shares will be made by the board of directors on the basis of Baytex's earnings, financial requirements and other conditions existing at such future time.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSE under the trading symbol "BTE".

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the information under the headings "Management's Discussion and Analysis" contained on pages 21 through 28 and "Quarterly Information" contained on page 46 of Baytex's annual report for the year ended December 31, 2001, which information is incorporated herein by reference.

SELECTED FINANCIAL INFORMATION

Summary of Operating Results

The following table sets forth selected financial information of the Company for the three years ended December 31, 2001.

(M$, except per share amounts)	Year Ended December 31 2001	2000	1999
Revenue	329,700	286,226	120,087
Cash flow from operations	144,070	155,326	62,703
Per share basic	2.91	3.68	1.77
Per share diluted	2.87	3.58	1.72
Net income (loss)	(128,509)	43,788	14,128
Per share basic	(2.60)	1.04	0.40
Per share diluted	(2.60)	1.01	0.39
Capital expenditures, net	376,085	384,857	74,313
Working capital (deficiency)	24,861	(42,374)	(20,247)
Long-term debt	403,922	213,883	116,382
Total assets	980,744	829,997	419,163

Note:

(1) There were no extraordinary items included in net earnings for the three-year period ended December 31, 2001.

(2) Net earnings per share were calculated using the weighted average number of Common Shares outstanding.

(3) Assumes exercise of employee and other stock options and all other convertible securities on their dates of issue.

INDUSTRY CONDITIONS

Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Baytex does not expect that any of these controls or regulations will affect its operations in a manner materially different than they would affect other oil and gas companies of similar size.

Crude oil and natural gas located in Alberta, Saskatchewan and British Columbia are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is privately owned and rights to explore for and produce oil and natural gas are granted by the mineral owners on negotiated terms and conditions.

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market and the value of refined products. Oil exports may be made under export contracts having terms not exceeding one year in the case of oil other than heavy oil, and not exceeding two years in the case of heavy oil, so long as an order approving any such export has been obtained from the National Energy Board. Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the National Energy Board and the issue of a license requires the approval of the Canadian federal government. The term of the license may not exceed 25 years.

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the

Government of Canada through the National Energy Board. Producers and exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet criteria prescribed by the National Energy Board. Natural gas exports for a term of two years or less, or for 2 to 20 years in quantities not more than 1.1 million cubic feet per day may be made under a National Energy Board order, or, in the case of exports for a longer duration or larger volumes, under a National Energy Board license and Canadian federal government approval.

The provincial governments of Alberta, British Columbia and Saskatchewan also regulate the removal of natural gas from those provinces for consumption elsewhere. They do so based on such factors as reserve availability, transportation arrangements and market considerations.

In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than government lands are determined by negotiations between the mineral owner and the lessee. Royalties on government land are determined by government regulation and are generally calculated as a percentage of the value of gross production, and the rate of royalties payable generally depends upon prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate deduction and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the government by virtue of the ARTC program. The ARTC program is based on a price sensitive formula, and ranges between 75%, for prices for oil at or below $100 per cubic meter ($15.90 per barrel), to 25%, for prices above $210 per cubic meter ($33.39 per barrel). In general, the ARTC rate is applied to a maximum of $2,000,000 of government royalties payable for each producer or associated group of producers. Government royalties on production from producing properties acquired from companies claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Crude oil and natural gas royalty and reductions for specific wells reduce the amount of royalties Baytex pays to the government.

The North American Free Trade Agreement among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-US Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, so long as any export restrictions do not:

- reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36 month period or another representative period agreed upon by the parties);

- impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports); or

- disrupt normal channels of supply.

All three countries are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Environmental

The oil and natural gas industry is governed by environmental regulation under Canadian federal and provincial laws, rules and regulations, which restrict and prohibit the release or emission and regulate the storage and transportation of various substances produced or utilized in association with oil and gas industry operations. In addition, applicable environmental laws require that well and facility sites be abandoned and reclaimed, to the satisfaction of provincial authorities, in order to prevent pollution from former operations. Also, environmental laws may impose upon "responsible persons" remediation obligations on property designated as a contaminated site. Responsible persons include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any present or past owner, tenant or other person in possession of the site. A breach of environmental laws may result in the imposition of fines and penalties, in addition to the costs of abandonment and reclamation.

All applicable environmental laws are consolidated in the *Environmental Protection and Enhancement Act*. Under this Act, environmental standards and requirements that apply to compliance, cleanup and reporting are stricter. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental increase in the cost of conducting oil and natural gas operations in Alberta.

Baytex has established guidelines and management systems to ensure compliance with environmental laws, rules and regulations. Baytex has designated a compliance officer whose responsibility is to monitor regulatory requirements and their impact on Baytex and to implement appropriate compliance procedures. Baytex also employs an environmental manager whose responsibilities include causing Baytex's operations to be carried out in accordance with applicable environmental guidelines and implementing adequate safety precautions. The existence of these positions cannot, however, guarantee total compliance with environmental laws, rules and regulations.

RISK FACTORS

An investment in Baytex may be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas and its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Baytex's competitive position depends on its geological, geophysical and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Baytex competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Baytex also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Baytex also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies will also provide competition for Baytex.

The marketability of oil and natural gas acquired or discovered is affected by numerous factors beyond the control of Baytex. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government which may be amended from time to time. See "Industry Conditions". Baytex's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Company believes that it is in material compliance with current applicable environmental regulations, changes to such regulations may have a material adverse effect on the Company. See "Industry Conditions - Environmental".

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Baytex's net production revenue and overall value and could result in ceiling test writedowns. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Baytex's reserves. Baytex might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Baytex's net production revenue causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Company are in part determined by the borrowing base of the Company. A substantial material decline in prices from historical average prices could further reduce the Company's borrowing base, therefore reducing the bank credit available to the Company and possibly require that a portion of the Company's bank debt be repaid.

The Company uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows. To the extent that such capitalized costs (net of accumulated depreciation and depletion) less future taxes exceed the present value of estimated future net cash flows from the Company's proved oil and natural gas reserves, those excess costs would be required to be charged to operations.

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases.

From time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Baytex maintains liability insurance in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Baytex could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent Baytex is not the operator of its oil and gas properties, Baytex will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Baytex which could result in a reduction of the revenue received by Baytex.

There are numerous uncertainties inherent in estimating quantities of reserve and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated effective December 31, 2001 by Outtrim. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Depending on future exploration and development plans, the Company may require additional financing which may not be available or, if available, may not be available on favourable terms.

Certain directors of Baytex are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Baytex's success depends in large measure on certain key personnel including Messrs. Dale 0. Shwed and Raymond T. Chan. The loss of the services of such key personnel could have a material adverse effect on Baytex. Baytex does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Company are likely to be of central importance. In addition, competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Baytex will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, is contained in the Management Proxy Circular of the Company dated April 12, 2002 provided for the annual meeting of the shareholders of the Company to be held on May 28, 2002. Additional financial information is also provided in the Company's consolidated financial statements for the year ended December 31, 2001 which are contained in the Annual Report of the Corporation for the year ended December 31, 2001.

Upon request the Company will provide to any person:

1. One copy of this Annual Information Form together with one copy of any document, or the pertinent pages of any document incorporated by reference in the Annual Information Form;

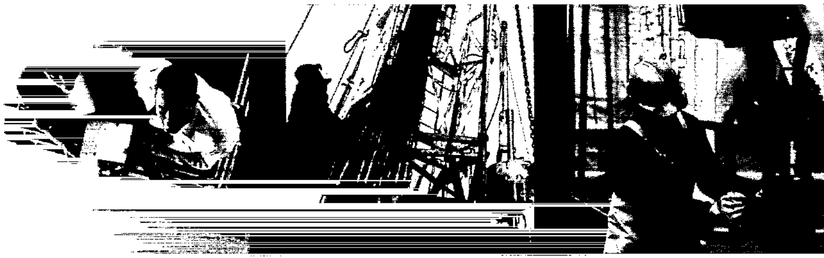
2. One copy of the Company's consolidated financial statements contained in the Annual Report for the year ended December 31, 2001, together with the report of the auditors thereon, and one copy of any of the Company's interim financial statements subsequent to such audited financial statements;

3. One copy of the Company's Management Proxy Circular provided for the annual meeting of the shareholders of the Company to be held on May 28, 2002; and

4. When the Company's securities are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of the Company's securities, also upon request to the Company, one copy of any other document that is incorporated by reference in the preliminary or final short form prospectus, as the case may be.

Copies of these documents may be obtained in some cases upon payment of a reasonable charge upon request to:

Baytex Energy Ltd.
Suite 2200, 205 - 5th Avenue S.W.
Calgary, Alberta
T2P 2V7
Phone: (403) 269-4282
Fax: (403) 205-3845



BAYTEX
ENERGY LTD.

2002

Q1 **FIRST INTERIM**
For the three months ended
March 31, 2002

HIGHLIGHTS

Three Months Ended March 31 (Unaudited)	**2002**	2001	% Change
FINANCIAL			
($ thousands, except per share amounts)			
Petroleum and natural gas sales	**79,130**	79,230	–
Cash flow from operations	**40,125**	37,617	7
Per share – basic	**0.77**	0.82	(6)
– diluted	**0.76**	0.80	(5)
Net income (loss)	**7,304**	(1,693)	n/a
Per share – basic	**0.14**	(0.04)	n/a
– diluted	**0.14**	(0.04)	n/a
Exploration and development	**39,991**	44,801	(11)
Dispositions – net	**(46,363)**	(295)	n/a
Total capital expenditures	**(6,372)**	44,506	n/a
Long-term notes	**330,249**	329,138	–
Bank loans	**22,179**	–	n/a
Other working capital	**31,255**	(46,690)	n/a
Total net debt	**383,683**	282,448	36
OPERATING			
Daily production			
Light oil (bbls/d)	**3,818**	3,911	(2)
Heavy oil (bbls/d)	**22,838**	25,970	(12)
Total oil (bbls/d)	**26,656**	29,881	(11)
Natural gas (mmcf/d)	**73.7**	57.6	28
Oil equivalent (boe/d @ 6:1)	**38,948**	39,483	(1)
Average prices (before hedging)			
WTI oil (US$/bbl)	**21.64**	28.73	(25)
Edmonton par oil ($/bbl)	**33.51**	43.00	(22)
BTE light oil ($/bbl)	**27.58**	38.65	(29)
BTE heavy oil ($/bbl)	**21.58**	14.62	48
BTE total oil ($/bbl)	**22.44**	17.77	26
BTE natural gas ($/mcf)	**3.19**	6.83	(53)
BTE oil equivalent ($/boe)	**21.39**	23.41	(9)
Weighted average shares (thousands)			
Basic	**52,027**	45,941	13
Diluted	**52,596**	47,066	12

MESSAGE TO SHAREHOLDERS

Baytex Energy Ltd. is pleased to announce its financial and operating results for the first quarter of 2002. These results clearly demonstrate the benefits of following a defined corporate strategy, the quality of our assets and the strength of our capital base. After enduring the longest slump in history for heavy oil prices, Baytex is enjoying the effects of a strong recovery of heavy oil fundamentals. Highlights of the first quarter include:

- Cash flow per share of $0.77 for the first quarter of 2002, 64 percent higher than the $0.47 for the fourth quarter of 2001. Under current production and pricing scenarios, cash flow for the second quarter of 2002 should reach $1.00 per share, 30 percent higher than that of the first quarter.
- Production for the first quarter averaged 38,948 boe/d. Current production is approximately 40,000 boe/d. The highly successful winter drilling program was entirely funded by cash flow from operations.
- Bank borrowings were reduced to $22.2 million as at March 31, 2002 as a result of the $120 million proceeds from asset dispositions and hedging gains. At the current rates of cash flow and capital spending, the Company's bank loans could be completely repaid during the third quarter of 2002.

HEAVY OIL PRICING

Lloyd Blend (LLK) differentials staged a remarkable recovery in the first quarter of 2002. After averaging a post-deregulation high of US$10.69 per barrel (42 percent of WTI price) in 2001, LLK differentials declined to US$6.89 (35 percent of WTI), US$5.68 (27 percent of WTI) and US$4.93 (20 percent of WTI), respectively, in January, February and March of 2002. These recent differentials are more in-line with the long-term historical levels, where LLK differentials had averaged US$5.82 (29 percent of WTI) over the last 16 years since deregulation in 1985. Corporately, heavy oil wellhead prices recovered from the low of $7.95 per barrel in November 2001 to $15.68 in January, $20.33 in February and $27.97 in March of 2002. Baytex's heavy oil production netback averaged $12.92 per barrel during the first quarter this year, evidencing the attractive re-investment efficiency of this commodity under normal pricing as the Company's finding and development costs associated with heavy oil reserves are generally in the $5.00 range.

OPERATIONS REVIEW

Capital expenditures for exploration and development activities totalled $40 million in the first quarter of 2002, and were entirely funded by cash flow from operations. This program included the drilling of 70 (64.8 net) wells, resulting in 31 (30.5 net) oil wells, 22 (17.8 net) gas wells, one (0.5 net) service well and 16 (16.0 net) dry holes. In terms of allocation between commodities, 35 of the wells drilled were targeting heavy oil, 32 for natural gas, two for light oil and one for water injection purposes.

When Baytex's 2002 capital budget was first set in early December, the Company had intended to defer heavy oil drilling until after spring break-up. With prices rebounding early in the new year, Baytex responded by accelerating the drilling of 35 wells into the first quarter and concurrently initiated a workover program to reactivate part of the shut-in production. The results of these actions were extremely rewarding, as heavy oil production averaged around 25,000 bbl/d in April, 16 percent higher than average production in December. Furthermore, the efficiency of the capital program is most evident here as capital expenditures of the Heavy Oil District in the first quarter totalled only $15 million, equating to the spending efficiency of $2,900 per barrel of production added, after accounting for normal production decline. Capital budget for the second quarter includes the drilling of 25 heavy oil wells with at least half of them in the Cold Lake property in Alberta. Although this property is currently producing only 1,300 bbl/d, it has the potential to become one of the Company's most significant heavy oil properties with second quarter drilling helping to delineate this prospect. Baytex, as planned, is continuing with solvent injection at its VAPEX pilot project at Carruthers and will update the progress of this project in the third quarter.

Baytex also experienced excellent success in its natural gas drilling program during the first quarter, with production added in every major property in its Northern and Plains districts. With average production in April of 74 mmcf/d, the first quarter capital program was able to completely replace production declines as well as the production sold in the asset divestiture program. A total of $25 million was expended by the Northern and Plains districts in the first quarter, yielding a capital efficiency of $15,000 per boe of production added during this period. The plan in the second quarter is to drill 20 wells targeting natural gas. However, inclement weather this spring may result in some of these wells being delayed to the third quarter, as the Company has yet to spud any wells so far in the second quarter.

OUTLOOK

Capital expenditures for exploration and development in the second quarter of 2002 are budgeted at $35 million. At the current rates of production and commodity prices, this level of spending should be substantially below cash flow from operations. The Company's plan is to maintain its total 2002 exploration and development capital budget at $120 million. Baytex will endeavour to enhance its operation focus and efficiency through core area property acquisitions and non-core area property dispositions. In the meantime, any excess cash flow over capital spending will be used to reduce bank loans. If the Company does not complete any significant acquisitions, bank borrowings should be completely repaid by mid-summer in 2002.

The Canadian economy is experiencing a stronger recovery compared to that of the United States, resulting in the recent strengthening in our dollar. Baytex is well positioned to benefit from this as virtually all of its debt is denominated in U.S. dollars. Furthermore, interest obligations are pegged to U.S. LIBOR rates, which have remained low as the United States government carefully manages its fragile economic recovery. Commodity prices should remain favourable as heavy oil is now entering its high seasonal demand period and natural gas prices look to maintain their surprising strength with improving supply/demand expectations.

The fundamentals of Baytex are strong. Cash flow for the second quarter in 2002 should reach $1.00 per share under current production levels and commodity prices. The Company is excited by its potential to continue to deliver superior returns to its shareholders.

On behalf of the Board of Directors

Dale O. Shwed
President and Chief Executive Officer
May 14, 2002

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2002 and 2001 and the audited consolidated financial statements for the year ended December 31, 2001. Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

PRODUCTION

Light oil production for the first quarter of 2002 decreased by two percent to 3,818 bbl/d from 3,911 bbl/d for the same period in 2001 due to the sale of properties in December 2001 and January 2002. Heavy oil production decreased by 12 percent to 22,838 bbl/d for the first three months of 2002 from 25,970 bbl/d for the same period last year. The decline was the result of property sale and the curtailment of spending on heavy oil drilling and maintenance projects in the second half of 2001. Natural gas production increased by 28 percent to 73.7 mmcf/d for the first quarter of 2002 compared to 57.6 mmcf/d for the same period last year due to the OGY and Triumph acquisitions in the second quarter of 2001 and a successful drilling program.

REVENUE

Revenue from light oil for the first quarter of 2002 decreased 30 percent from the corresponding period in 2001 due to a 29 percent decrease in wellhead prices and a two percent decrease in production. Revenue from heavy oil increased 30 percent due to a 48 percent increase in wellhead prices offset by a 12 percent decline in production. Natural gas revenue declined 40 percent due to a decrease of 53 percent in wellhead prices offset by a 28 percent increase in production.

Three Months Ended March 31	**2002**		2001	
	$000s	**$/Unit**	$000s	$/Unit
Oil Revenue (barrels)				
Light oil	**9,476**	**27.58**	13,605	38.65
Heavy oil	**44,359**	**21.58**	34,180	14.62
Derivative contracts gain (loss)	**2,444**	**1.02**	(3,955)	(1.47)
Total oil revenue	**56,279**	**23.46**	43,830	16.30
Natural gas revenue (mcf)	**21,159**	**3.19**	35,400	6.83
Derivative contracts gain	**1,692**	**0.25**	–	–
Total natural gas revenue	**22,851**	**3.44**	35,400	6.83
Total Revenue (boe @ 6:1)	**79,130**	**22.57**	79,230	22.30

ROYALTIES

Total royalties decreased 24 percent to $11.8 million for the three months ended March 31, 2002 from $15.4 million for the same period last year. Total royalties for the first quarter of 2002 declined to 15.7 percent of sales compared to 18.6 percent of sales for the same period in 2001 due to the increase in heavy oil sales, which have a lower royalty rate in comparison to light oil and natural gas. Royalties as a percentage of sales by product were 17.0 percent for light oil, 12.7 percent for heavy oil, and 21.6 percent for natural gas in the first quarter of 2002 compared to 19.9, 9.1 and 27.1 percent, respectively, for the same period last year.

OPERATING EXPENSES

Operating expenses for the first quarter of 2002 increased two percent to $18.3 million from $17.8 million for the corresponding quarter last year. This increase is primarily attributable to the costs incurred to restore heavy oil wells that were shut-in during the fourth quarter of 2001. Operating expenses were $5.21 per boe for the first three months of 2002 compared to $5.02 per boe for the first quarter of 2001. For the first quarter of 2002, operating expenses were $6.25 per barrel of light oil, $5.91 per barrel of heavy oil and $0.60 per mcf of natural gas. Operating expenses by product for the same period last year were $5.96, $5.48 and $0.57, respectively.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses for the first three months of 2002 increased to $1.6 million from $1.1 million for the same quarter of 2001 as a result of increased staff levels associated with the Company's 2001 corporate acquisitions. On a per unit of production basis, these expenses increased from $0.32 per boe in 2001 to $0.45 per boe in 2002. In accordance with the full cost accounting policy, $1.6 million of expenses relating to exploration and development activities were capitalized in the first quarter of 2002 compared to $1.1 million during the same period in 2001.

INTEREST EXPENSES

Interest expenses on long-term debt were unchanged at $5.4 million for the first quarter of 2002 and 2001. While average debt levels were higher in the first quarter of 2002, interest rates on the Company's senior secured notes and senior subordinated notes were reduced from 7.23 to 4.7 percent and 10.5 to 7.1 percent, respectively, as a result of the interest rate swaps that the Company negotiated in December 2001.

DEPLETION, DEPRECIATION AND AMORTIZATION

The provision for depletion, depreciation and amortization increased to $26.3 million for the first three months of 2002 compared to $24.9 million for the same quarter last year. On a unit of production basis, the current period provision was $7.49 per boe compared to $7.02 per boe in the same period last year. This increase was the result of the acquisitions of OGY and Triumph in the second quarter of 2001.

SITE RESTORATION COSTS

Site restoration costs of $0.8 million for the first quarter of 2002 represent a decrease from $1.0 million for the same quarter last year. On a unit of production basis, the provision for the first quarter of 2001 was $0.23 per boe compared to $0.29 per boe for the corresponding quarter of last year.

FOREIGN EXCHANGE

Effective January 1, 2002, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") amended accounting standard with respect to foreign currency translation. The amended standard eliminates the practice to defer and amortize foreign exchange gains and losses on long-term monetary items. As a result, all foreign exchange gains and losses on long-term monetary items are now recognized in earnings based on the exchange rates at the end of the reporting periods. The amended standard also requires that prior year's comparative figures be restated to comply with the new standard.

The application of the new standard resulted in an unrealized foreign exchange loss of $0.2 million in the first quarter of 2002 compared to a $13.1 million loss in the first quarter of 2001. The 2002 loss is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.6275 at March 31, 2002 compared to 0.6279 at December 31, 2001. The 2001 loss is based on the translation of the U.S. dollar denominated senior secured notes at 0.6340 at March 31, 2001 compared to 0.6666 at December 31, 2000 along with the senior subordinated notes translated at 0.6340 at March 31, 2001 compared to 0.6582 on February 13, 2001 when the notes were issued.

INCOME TAXES

Current tax expenses were $2.0 million for the first quarter of 2002 compared to $1.8 million for the same quarter of 2001. The current tax expenses are comprised of $1.6 million of Saskatchewan Capital Tax and $0.4 million of Large Corporation Tax compared to $1.4 million and $0.4 million, respectively, for the same period in 2001.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2002, total net debt (including working capital) was $383.7 million compared to $282.4 million at the end of the first quarter of 2001 and $379.1 million at December 31, 2001. The increase in total debt at the end of the first quarter of 2002 compared to 2001 was the result of the acquisitions that the company completed in 2001.

Effective January 1, 2002, the CICA's Emerging Issues Committee issued an abstract giving guidance on disclosure of callable debt obligations. Specifically, the abstract requires the classification of borrowings under a 364-day revolving credit facility as current liabilities. The Company's bank loans are structured under this type of credit facility and, as such, have been reclassified as current liabilities.

The senior secured notes are governed by certain financial covenants measured at the end of each fiscal quarter. The principal covenants are: (i) consolidated tangible net worth not to be less than $200 million, excluding accounting ceiling test write-down (such net worth was $481.9 million as at March 31, 2002); (ii) consolidated total debt not to exceed 300% of consolidated cash flow (such ratio was 190% as at March 31, 2002); and (iii) consolidated cash flow not to be less than 400% of consolidated interest expense (such ratio was 549 percent as at March 31, 2002). The senior subordinated notes are due February 2011 and do not require any financial covenant maintenance.

CAPITAL EXPENDITURES

Total exploration and development expenditures decreased to $40.0 million for the first quarter of 2002 compared to $44.8 million for the same period in 2001. The Company's total capital expenditures for these periods are summarized as follows:

Three Months Ended March 31 ($ thousands)	**2002**	2001
Land	**2,233**	1,619
Seismic	**2,030**	3,068
Drilling and completions	**25,709**	22,297
Equipment	**8,070**	15,856
Other	**1,949**	1,961
Total exploration and development	**39,991**	44,801
Property acquisitions	**690**	623
Property dispositions	**(47,053)**	(918)
Net capital expenditures	**(6,372)**	44,506

CONSOLIDATED BALANCE SHEETS

(thousands) (Unaudited)	March 31 2002	December 31 2001 (restated – note 2)
ASSETS		
Current assets		
Accounts receivable	**$ 45,718**	$ 44,300
Properties held for sale	**–**	46,895
	45,718	91,195
Deferred financing charges	**8,414**	8,674
Petroleum and natural gas properties	**881,232**	867,177
	$ 935,364	$ 967,046
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 76,973**	$ 64,334
Current portion of long-term debt (note 3)	**22,179**	75,820
	99,152	140,154
Long-term debt (note 3)	**330,249**	330,102
Deferred revenue	**14,085**	18,694
Provision for future site restoration costs	**21,337**	20,541
Future income taxes	**152,023**	146,446
	616,846	655,937
SHAREHOLDERS' EQUITY		
Share capital (note 4)	**394,839**	394,734
Deficit	**(76,321)**	(83,625)
	318,518	311,109
	$ 935,364	$ 967,046

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

For the Three Months Ended March 31 (thousands, except per share data) (Unaudited)	**2002**	2001
Revenue		(restated – note 2)
Petroleum and natural gas sales	**$ 79,130**	$ 79,230
Royalties	**(11,782)**	(15,433)
	67,348	63,979
Expenses		
Operating	**18,271**	17,845
General and administrative	**1,587**	1,122
Interest on long-term debt	**5,370**	5,373
Foreign exchange (note 2)	**186**	13,115
Depletion, depreciation and amortization	**26,262**	24,943
Site restoration costs	**796**	1,024
	52,472	63,422
Income before income taxes	**14,876**	375
Income taxes		
Current	**1,995**	1,840
Future	**5,577**	228
	7,572	2,068
Net income (loss)	**7,304**	(1,693)
Retained earnings (deficit), beginning of period, as previously reported	**(75,954)**	52,555
Accounting policy change (note 2)	**(7,671)**	927
Retained earnings (deficit), beginning of period, as restated	**(83,625)**	53,482
Retained earnings (deficit), end of period	**$ (76,321)**	$ 51,789
Net income (loss) per share		
Basic	**$ 0.14**	$ (0.04)
Diluted	**$ 0.14**	$ (0.04)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Three Months Ended March 31 (thousands, except per share data) (Unaudited)	2002	2001
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net income (loss)	**$ 7,304**	$ (1,693)
Items not affecting cash:		
Site restoration costs	**796**	1,024
Foreign exchange	**186**	13,115
Depletion, depreciation and amortization	**26,262**	24,943
Future income taxes	**5,577**	228
Cash flow from operations	**40,125**	37,617
Change in non-cash working capital	**(15,318)**	(6,102)
Deferred revenue	**(4,609)**	–
	20,198	31,515
FINANCING ACTIVITIES		
Issue of senior subordinated term notes	**–**	227,895
Decrease in bank loan	**(51,679)**	(125,755)
Increase in deferred financing charges	**–**	(8,122)
Issue of shares (net of issue expenses)	**105**	1,199
	(51,574)	95,217
INVESTING ACTIVITIES		
Petroleum and natural gas property expenditures	**(40,681)**	(45,424)
Disposal of petroleum and natural gas properties	**47,053**	918
Decrease in materials and supplies	**465**	736
Properties held for sale	**(46,895)**	–
Change in non-cash working capital	**71,434**	88
	31,376	(43,682)
Change in cash	**–**	83,050
Cash, beginning of period	**–**	–
Cash, end of period	**$ –**	$ 83,050
Cash flow from operations per share		
Basic	**$ 0.77**	$ 0.82
Diluted	**$ 0.76**	$ 0.80

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Three Months Ended March 31, 2002 and 2001 (Unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Baytex Energy Ltd. (the "Company") 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 of the Company as at December 31, 2001, except as described in note 2. The interim consolidated financial statements contain disclosures, which are supplemental to the Company's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2001.

2. CHANGE IN ACCOUNTING POLICY

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants (CICA) amended accounting standard with respect to accounting 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 recognized in income. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item. The impact of the amended standard on current quarters' results was to decrease net income by $186,000 and increase the opening deficit by $7.7 million representing the cumulative effect of deferred foreign exchange losses at January 1, 2002.

The impact on the comparative balances was a decrease in unrealized foreign exchange loss at December 31, 2001 of $13.7 million, an increase in foreign exchange expense of $13.1 million, a decrease in net income of $7.2 million and an increase in opening retained earnings of $0.9 million.

3. LONG-TERM DEBT

(thousands)	**March 31, 2002**	December 31, 2001
Bank loan	**$ 22,179**	$ 73,820
Senior secured term notes (US$57,000,000)	**90,830**	90,778
Senior subordinated term notes (US$150,000,000)	**239,025**	238,890
Other long-term debt	**394**	2,434
	352,428	405,922
Less: current portion	**22,179**	75,820
	$ 330,249	$ 330,102

Effective January 1, 2002, the Company has classified borrowing under its bank facilities as current liability as required by new guidance under the CICA's Emerging Issues Committee Abstract 122. The bank loan at December 31, 2001 has been restated to conform with current presentation.

Bank loan

At March 31, 2002, the bank facilities were limited to a total commitment under the facilities of $85 million and a borrowing base of $175 million.

4. SHARE CAPITAL

The Company has an unlimited number of common shares in its authorized share capital.

Issued and Outstanding:

Common shares

(thousands)	*# of shares*	*Amount*
Balance – January 1, 2002	52,008	$ 394,734
Exercise of stock options	28	105
Balance – March 31, 2002	**52,036**	**$ 394,839**

Stock options

(thousands)	# of options	Weighted average exercise price
Balance – January 1, 2002	4,468	$ 6.19
Granted	19	5.50
Exercised	(28)	3.80
Cancelled	(42)	4.72
Balance – March 31, 2002	**4,417**	**$ 6.21**
Exercisable – March 31, 2002	**1,799**	**$ 6.13**

The Company accounts for its stock options using the intrinsic-value method. Under the intrinsic-value method, compensation costs are not required to be recognized in the financial statements for stock options granted at market value. Had compensation costs for the Company's stock option plan been determined based on the fair-value method at the dates of grants under the plan after January 1, 2002, the Company's pro-forma net income and earnings per share would be the same as those reported.

5. DERIVATIVE CONTRACTS

For the year 2003, the Company has entered into oil price collar contracts for 10,000 bbl/d between WTI US$20.00 and an average US$26.56.

6. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's presentation.

CORPORATE INFORMATION

BOARD OF DIRECTORS

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W.A. Blake Cassidy
Retired Banker

Raymond T. Chan
Senior Vice-President
Baytex Energy Ltd.

Fred C. Coles
Independent Businessman

Dennis L. Nerland
Partner
Shea Nerland Calnan

Dale O. Shwed
President
Baytex Energy Ltd.

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

Raymond T. Chan, CA
Senior Vice-President and
Chief Financial Officer

Ralph W. Gibson
Vice-President, Marketing

Daniel B. Horner, LLB
Vice-President, Land

John G. Leach, CA
Vice-President, Finance
and Administration

S. Dale McAuley
Vice-President, Operations

Richard W. Naden
Vice-President, Production

Garry J. Wasylycia
Vice-President, Exploration

Shannon M. Gangl
Secretary
Partner
Burnet, Duckworth & Palmer LLP

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BANKERS
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Bank of Montreal
BNP Paribas (Canada)

LEGAL COUNSEL
Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS
Outtrim Szabo Associates Ltd.

TRANSFER AGENT
Valiant Trust Company

EXCHANGE LISTING
The Toronto Stock Exchange
Stock Symbol BTE

ADVISORY

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow and debt levels. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Company's areas of operations; and other factors, many of which are beyond the control of the Company. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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ENERGY LTD.

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May 28, 2002

Alberta Securities Commission *(via SEDAR)*
British Columbia Securities Commission *(via SEDAR)*
Saskatchewan Securities Commission *(via SEDAR)*
Manitoba Securities Commission *(via SEDAR)*
Ontario Securities Commission *(via SEDAR)*
Quebec Securities Commission *(via SEDAR)*
Nova Scotia Securities Commission *(via SEDAR)*
Newfoundland Securities Commission *(via SEDAR)*
The Toronto Stock Exchange *(via SEDAR)*

Dear Sirs:

Re: Baytex Energy Ltd.
Mailing of First Quarter Report
to Registered Shareholders

As the mailing agent for Baytex Energy Ltd., we are pleased to confirm the mailing of the first quarter report for the period ended March 31, 2002, to each of the Registered Shareholders of the subject corporation on **May 28, 2002**.

We trust this is satisfactory.

Yours truly,

"Cheryl Dahlager"
Cheryl Dahlager
Senior Account Manager

c.c. Baytex Energy Ltd.
Attn: Mr. John Leach

DECLARATION AS TO MAILING

PROVINCE	)	IN THE MATTER OF INTERIM MAILING TO THE
OF	)	SHAREHOLDERS OF **BAYTEX ENERGY LTD.**
ALBERTA	)	("CORPORATION").

I, CHERYL DAHLAGER, OF THE CITY OF CALGARY IN THE PROVINCE OF ALBERTA, DO SOLEMNLY DECLARE AS FOLLOWS:

1. I AM AN EMPLOYEE OF VALIANT TRUST COMPANY AND AS SUCH, HAVE KNOWLEDGE OF THE MATTERS HEREINAFTER DECLARED.

2. I CAUSED TO BE MAILED ON **MAY 28, 2002**, IN A FIRST CLASS PREPAID ENVELOPE ADDRESSED TO EACH OF THE PERSONS OR FIRMS WHO **WERE THE REGISTERED HOLDERS OF COMMON SHARES OF THE CORPORATION;**

   (a) **a copy of the FIRST QUARTER REPORT FOR THE PERIOD ENDED MARCH 31, 2002 marked EXHIBIT "A" and identified by me;**

AND I MAKE THIS SOLEMN DECLARATION CONSCIENTIOUSLY BELIEVING IT TO BE TRUE AND KNOWING THAT IT IS OF THE SAME FORCE AND EFFECT AS IF MADE UNDER OATH AND BY VIRTUE OF THE CANADA EVIDENCE ACT.

DECLARED BEFORE ME AT THE CITY OF)
CALGARY IN THE PROVINCE OF ALBERTA)
THIS 28TH DAY OF MAY 2002.)
)
)
)

____________"Pam Elliott"__________________
COMMISSIONER FOR OATHS IN AND FOR
THE PROVINCE OF ALBERTA
My commission expires on November 15, 2003.

________"Cheryl Dahlager"________
CHERYL DAHLAGER