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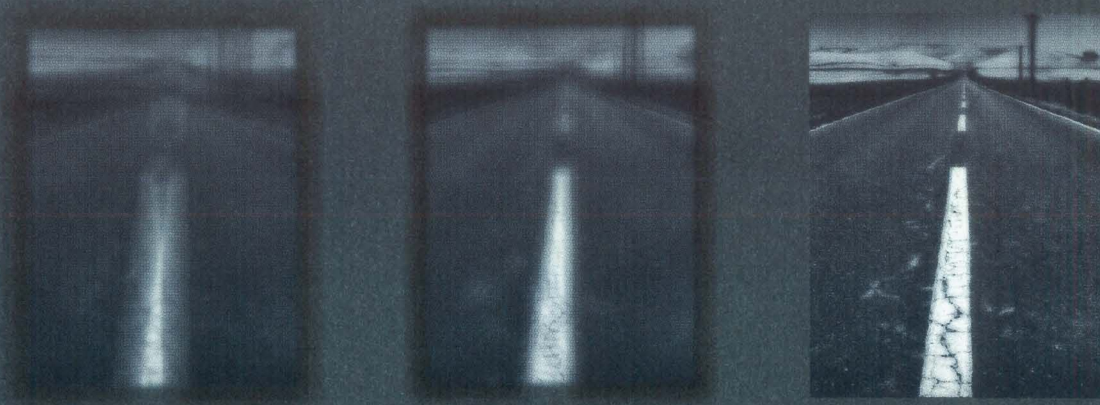

FOCUSED ON THE ROAD AHEAD

BEAU

CANADA EXPLORATION LTD

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NOTICE OF ANNUAL MEETING

The Annual General Meeting for the Shareholders of Beau Canada Exploration Ltd. will be held on July 25th, 2000 at 3:00 p.m. at the Westin Hotel, Belaire Room, Calgary, Alberta.

corporate highlights

	Three months ended 2000	1999	% change	Year ended December 31 1999	1998	% change
FINANCIAL *($000)*						
Revenue	$ 37,283	$ 25,652	45	$ 126,804	$ 108,870	16
Cash Flow	16,353	10,529	55	55,511	45,451	22
per share (Basic)	0.18	0.12	50	0.61	0.50	22
Net Income from						
continuing operations	2,087	(1,375)	252	(4,800)[1]	12,474[1]	(138)
per share (Basic)	0.02	(0.01)	300	(0.07)[1]	0.13[1]	(154)
Net Income (loss)	(8,357)	(1,415)	(491)	(4,800)	12,474	(138)
per share (Basic)	(0.10)	(0.02)	(400)	(0.07)	0.13	(154)
PRODUCTION						
Gas *(mmcf/d)*	76.2	90.1	(15)	89.1	91.1	(2)
Oil & NGLs *(bbls/d)*	8,095	6,418	26	7,038	8,303	(15)
Barrels of oil equivalent/d (10:1)	15,714	15,431	2	15,948	17,409	(8)
Barrels of oil equivalent (6:1)	20,793	21,439	(3)	21,888	23,479	(7)
AVERAGE PRICES						
Gas *($/mcf)*	2.32	2.29	1	2.34	1.89	24
Oil & Liquids *($/bbl)*	28.81	12.26	135	19.76	15.20	30
RESERVES						
Proven						
Gas *(bcf)*				286	298	(4)
Oil and NGLs *(mmbls)*				25.2	22.0	15
Proven and probable						
Gas *(bcf)*				407	412	(1)
Oil and NGLs *(mmbls)*				33.7	29.3	15
LAND						
Developed (net acres)	183,000	196,000	(7)	196,000	192,000	2
Undeveloped (net acres)	506,000	533,000	(5)	552,000	495,000	12
SHARES OUTSTANDING *(000s)*						
Average	91,951	91,538	0	91,753	90,840	1
Period end	91,953	91,568	0	91,943	91,511	0

	Three months ended March 31 2000		1999		Year ended December 31 1999		1998	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
DRILLING RESULTS								
Gas Wells	16	12.7	11	8.9	26	18.8	43	32.0
Oil Wells	19	15.1	2	2.0	31	22.0	7	3.1
Dry and Abandoned	6	4.4	7	7.0	17	13.9	5	5.0
	41	32.2	20	17.9	74	54.7	55	40.1
Success Rate		86%		61%		75%		88%

[1] *Operations had not been discontinued at year end. Therefore, numbers are not restated.*

At Beau Canada, being mindful of our responsibilities to, and reliance upon our employees and our suppliers, our primary objective is to maximize value for our shareholders. We will do this by exploiting and monetizing the assets of the Company as a whole, by managing our resources and our obligations with diligence and skill, and by maintaining a governance structure that reflects a constructive relationship for all concerned. Our Board views corporate governance as a fundamental contract between the Company and its shareholders.

Maximizing value for our shareholders was the driving force behind Beau Canada's strategic shift four years ago to become a company more focused on natural gas. Beau Canada looked ahead to emerging natural gas markets in North America and accelerated the Company's natural gas focus through a series of acquisitions and dispositions of non-core properties. This strategic move created a portfolio of high quality gas properties with the potential for large production and reserve gains, and a substantial base of natural gas production. To balance this natural gas focus, the Company maintained a strong base of oil properties including heavy oil. Since mid-1999 when oil prices began a solid recovery, drilling has been reactivated and significant increases have been recorded in oil and NGLs production.

In keeping with the focus of maximizing value for shareholders, Beau Canada's team of highly skilled oil and gas professionals has a track record of growth through the drill bit. Gas production is currently 93 mmcf/d, up from an average of 89.1 mmcf/d in 1999 – a 46 per cent increase over the 1996 average of 61 mmcf/d when we initiated our focus on gas. The majority of the increase in 2000 was from a significant Slave Point discovery drilled over the past winter in northeast British Columbia/northwest Alberta.

As we move forward in 2000, Beau Canada has embarked on a more aggressive strategy to maximize shareholder value. We are evaluating our options as a Company and we are looking at various options that will lead to value realization opportunities. Considerable progress has been made since the beginning of 2000; we have addressed specific issues and increased our flexibility in order to complete a thorough evaluation of alternatives.

SETTING A NEW COURSE

On May 10, 2000, Bruce Libin and Ed Chwyl joined the Board of Directors and the Board established a Special Committee comprised of independent directors to assist the Company in examining options to maximize shareholder value. These alternatives could include the sale of all or part of Beau Canada's assets, or recommending to shareholders the sale of all of the shares of the Company. Recognizing the need to be accountable to our shareholders, the Company's annual meeting was deferred until developments could be reported to our owners. We are pleased to announce a number of recent important developments.

Board and Management Changes

Considering the important role of the Special Committee in charting Beau Canada's strategic course, a number of changes have been made to senior management. Bruce Libin has been appointed Chairman and Michael Lang, Vice-Chairman, has been appointed Chief Financial Officer, a position he held in

1997. Tom Bugg, the founder of the modern Beau Canada and the architect of its growth into an intermediate oil and gas producer over the past 10 years, has left the Company but continues as President and Chief Executive Officer of Genoil Inc. With the Board focused on strategic initiatives and having confidence in operating management, there are no plans to appoint a new President. On June 15, 2000, Jeff Smith joined the Board of Directors.

Renegotiated Credit Facilities

We renegotiated the terms of a $42.3 million Subordinated Term Credit Facility with Enron Capital & Trade Canada and extended the due date to December 12, 2000 from June 11, 2000. This extension has eliminated a great deal of short term uncertainty and provides the opportunity to better deal with our balance sheet. The new terms include the removal of the equity conversion option that was available to both Enron and Beau Canada. It is our intention to repay this facility on or before the new due date and a number of repayment options are currently being evaluated, including asset sales or refinancing. In addition, we are in the process of the annual credit renewal with our bankers. We are satisfied with the negotiations to date and expect to report a satisfactory outcome shortly.

Corporate Sale Process

During May, a data room was opened in order to solicit offers for the Company. This process has been suspended temporarily to allow a number of outstanding issues to be addressed. We are cleaning up specific issues to provide more flexibility and more options for potential investors and shareholders as we move forward.

Property Dispositions

Since the start of 2000, our program, focused on adding value, has resulted in the sale of Beau Canada's interests in two properties, Helmet and Bantry. Production associated with these properties amounted to 6.5 mmcf/d of gas and 600 bbls/d of oil and NGLs. Proceeds of $34 million from both transactions have been applied to working capital. These dispositions, combined with stronger net cash flow in the second and third quarters, should return our working capital to historical levels. This is expected to improve our financial flexibility and expand our ability to pursue options to the greatest benefit of shareholders.

Genoil Share Distribution

At our upcoming annual meeting, shareholders will be asked to approve a capital reorganization whereby the Company's controlling interest in Genoil Inc. will be distributed to Beau Canada shareholders. Genoil, through its subsidiary CE3 Technologies Inc., has a number of promising technologies and opportunities. However, at this time, the Board has decided that Beau Canada will no longer support the emerging technology business. The share reorganization is considered the best alternative for Beau Canada shareholders to have an opportunity to choose to participate in Genoil's future, and the most viable option to allow Genoil to capitalize on its own potential.

FINANCIAL AND OPERATIONAL RESULTS

The postponement of our annual meeting has allowed us to publish our annual report later than usual and include results for the first quarter of 2000. Cash flow for the quarter was up 55 percent over first quarter 1999 to $16.4 million, reflecting a strong 135 percent increase in oil and NGL prices and a 26 percent increase in oil and NGL production to 8,095 bbls/d. This cash flow level was achieved despite the sale of properties and facility downtime which reduced gas production by 16 percent to 76.2 mmcf/d from first quarter 1999.

For the 1999 year end, Beau Canada recorded a loss of $4.8 million compared with a profit of $12.5 million in 1998. The loss includes a write-down of $7.2 million after tax and minority interest on the carrying value of Cuban properties due to an unsuccessful onshore exploration program through our subsidiary Genoil Inc. The Company had identified the Cuban operations as a high-risk venture and was able to somewhat mitigate that risk by raising cash through the sale of Genoil's offshore acreage. However, early drilling results pointed to the prudent investment decision to refocus on the Company's core business in Western Canada. Before this write down, Beau Canada recorded earnings of $4.3 million. In first quarter 2000, we announced our intent to distribute our shares in Genoil to Beau Canada shareholders and recorded a loss from discontinued operations of $10.4 million. This write-down caused our loss of $8.4 million for the quarter.

CONTINUING TO ADD VALUE THROUGH THE DRILL BIT

The Company maintained a relatively active exploration and development program over the past 18 months. The focus in western Canada is to add shareholder value through the drill bit, primarily in the exploration and development of natural gas and NGLs. Since January 1, 1999, more than 85 percent of the capital budget was spent on natural gas and exploration and development in a fairway extending from northeast British Columbia through northwest Alberta and west central Alberta. More than 60 percent of Beau Canada's undeveloped lands are located in this liquids-rich gas fairway and accounted for 34 (25.0 net) of the 74 (54.7 net) wells drilled in 1999. In first quarter 2000, the Company participated in 41 wells (32.2 net) with the majority being drilled for natural gas in northeast British Columbia and western Alberta.

In the winter 1999/2000 drilling season, Beau Canada made significant Slave Point gas discoveries at Ladyfern in northeast British Columbia and in the South Hamburg area in Alberta. In the first quarter 2000, three gas wells were tied-in adding approximately 16 mmcf/d net to Beau Canada. Since January, the Company has continued to acquire lands on the prospect. Based on drilling results and interpretation of 3-D seismic, excellent potential exists for future exploration and development on these lands and drilling is expected to commence next winter.

Beau Canada's success in Slave Point exploration has provided a strong technical and operational advantage in similar plays and increased the Company's confidence in other nearby areas such as Chinchaga and Cranberry where we hold large undeveloped land positions. In first quarter 2000, 3-D seismic was shot over both areas and drilling locations are being determined for the 2000/2001 drilling season.

Our west central Alberta properties remain a focus for exploration and development of liquids-rich natural gas. The Company is continuing to build its land position and prospect inventory in this area where multi-zone plays continue to provide lower risk drilling and production gains.

With the rise in crude oil prices in 1999, our heavy oil operations saw renewed activity. Heavy oil production was 1,700 bbls/d in January 1999, but exceeded 3,800 bbls/d in December 1999, through a moderate level of drilling and re-activation of shut-in wells. Heavy oil volumes accounted for about 45 percent of the Company's first quarter 2000 production of 8,095 bbls/d of oil and NGLs.

FOCUSED ON SHAREHOLDER VALUE

At Beau Canada, we are focused on shareholder value. Beau Canada's success at building a base of natural gas-prone assets, along with our exploration successes, have increased the value of the Company. We are confident that any new financial, corporate or operational arrangement will be of even greater benefit to shareholders.

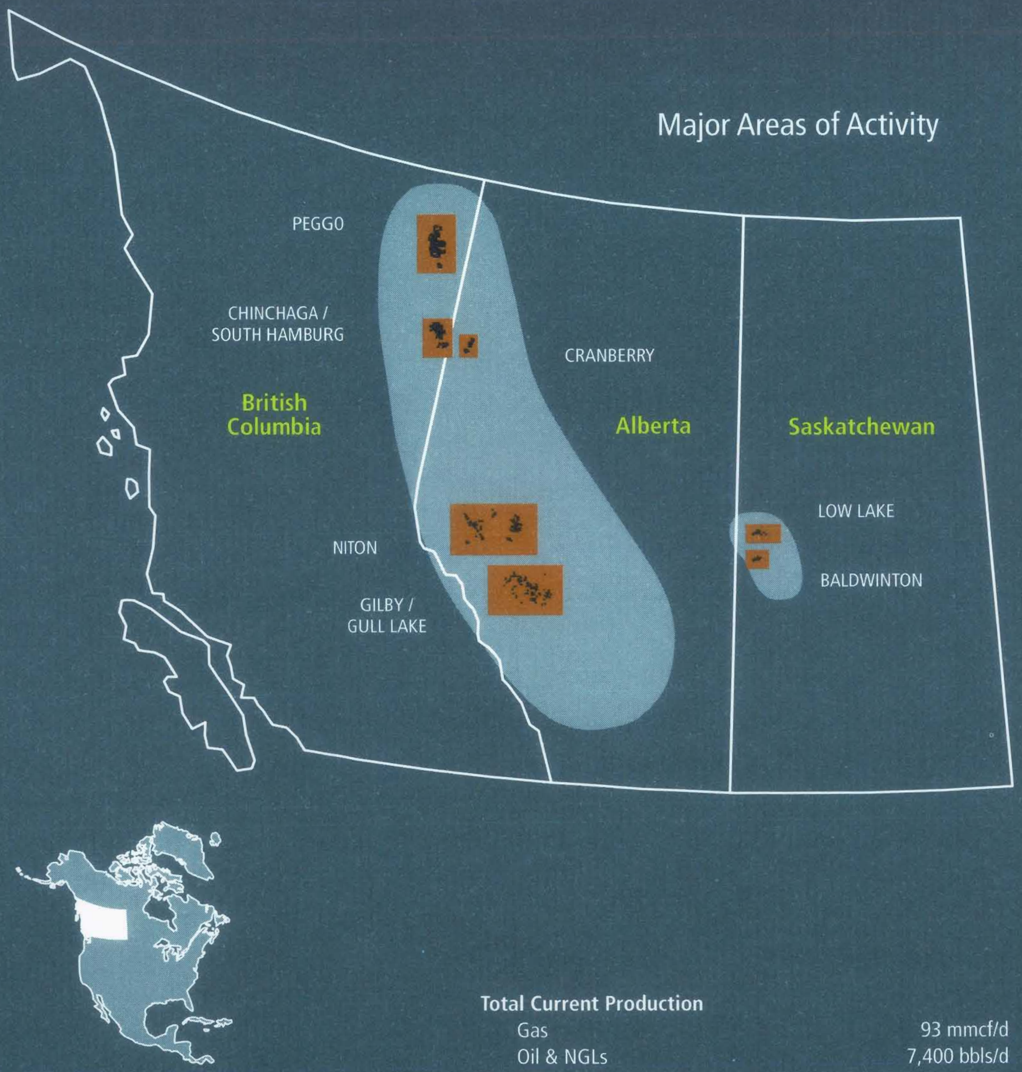
At our annual meeting, we will be able to tell our shareholders more about Beau Canada's business and prospects and our continuing efforts to maximize value. In turn, our shareholders will have the opportunity to vote on the Genoil share distribution and for a revitalized Board of Directors.

On behalf of the Beau Canada shareholders, we want to thank our employees, the men and women whose daily efforts make all success possible. Any accretions in value are due to their skills, dedication and commitment.

On behalf of the Board of Directors

Bruce R. Libin, Q.C.
Chairman of the Board
June 19, 2000

Please visit our website at www.beaucanada.com for information on Beau Canada. The website will be updated with all important corporate news and developments.



Total Current Production	
Gas	93 mmcf/d
Oil & NGLs	7,400 bbls/d
Operated Production	80%

ACTIVITIES OVERVIEW

Beau Canada is committed to adding shareholder value through exploration and development of natural gas in western Canada. In addition, the Company's substantial land position in west central Saskatchewan provides numerous opportunities to add value through the exploitation and development of its heavy oil assets. In 1999 and 2000 we expanded our natural gas asset base and took advantage of strong oil prices in the second half of 1999 and early 2000 by exploiting our heavy oil properties.

Gas Activities

Since January 1, 1999, we spent more than 85 percent of our capital budget expanding our land position, acquiring seismic, exploring for and developing natural gas reserves in western Alberta and northeastern British Columbia. We had significant drilling programs in the Peggo and Ladyfern areas of northeastern British Columbia and the South Hamburg and Cranberry areas of northwestern Alberta. The Peggo program was a continuation of the development of our extensive land holdings in this gas prone area. The South Hamburg exploration program, including the Ladyfern area, resulted in major Slave Point formation discoveries, adding significantly to our gas reserves. The discoveries will contribute to increased production and cash flow for 2000 and add significantly to future growth in the area. Further exploration and development drilling is planned in these areas in 2000/2001.

This successful exploration program has also enhanced the prospects for Beau Canada's large land holdings immediately northwest at Chinchaga, where the Company is currently producing from the Slave Point. Utilization of 3-D seismic at South Hamburg contributed significantly to this success. Based upon this experience, Beau Canada shot a 154 km^2 3-D seismic program over a portion of our lands at Chinchaga. As a result, a number of Slave Point locations have been identified on the seismic for drilling in the winter of 2000/2001. In addition, the Company plans to shoot a 3-D seismic program in the 2000/2001 winter season to evaluate a portion of its undeveloped land between Chinchaga and South Hamburg for Slave Point potential.

In the Cranberry area, east of the South Hamburg discovery, we continued our Slave Point exploration program by acquiring a sizeable land position and drilling four Slave Point gas wells over the past three years. Two wells were on production in 1999, a third was tied-in in the first quarter of 2000 and the fourth will be tied-in in the near future. The Company recently shot a 54 km^2 3-D seismic program over its 100 percent interest acreage with preliminary interpretations indicating two to four Slave Point locations. We plan to drill these locations in 2000/2001.

During the first quarter of 2000, Beau Canada also made natural gas discoveries in the Jedney and Aitken Creek areas of northeastern British Columbia. As well, Beau Canada was active in west central Alberta in 1999 and in the first quarter of 2000 drilling primarily for liquids rich natural gas; much of this gas will be tied-in in 2000. The Company is continuing to add to its land position and prospect inventory in these areas.

Oil Activities

With oil prices strengthening in mid-1999, Beau Canada again became active in west central Saskatchewan drilling low to medium risk heavy oil development wells and bringing back on production previously shut-in wells. As a result, production rose dramatically from an initial rate of 1,700 bbls/d in January 1999 to 3,900 bbls/d in May 2000. Approximately 1,400 bbls/d of this increase came through drilling activity. Continued growth in this area is planned as the Company exploits its significant land position and technical expertise in heavy oil development.

Dispositions

Beau Canada disposed of a number of non-core properties in 1999 and early 2000. In late 1999, we sold our 8.2 percent interest in the Court Bakken Unit No. 1 in west central Saskatchewan. Production associated with this disposition was approximately 180 bbls/d of oil. In early 2000, we disposed of our Helmet property in northeastern British Columbia. The property was producing approximately 4 mmcf/d of gas from the Slave Point and Jean Marie formations. In May 2000, we disposed of our Bantry property in southern Alberta. The property consisted of a 100 percent working interest in a gas plant, a gathering system and an interest in the Bantry Mannville "A" oil pool. Production from the Bantry property was approximately 2.5 mmcf/d of gas and 600 bbls/d of oil and NGLs. Proceeds from these three dispositions totalled $37 million.

PRODUCTION

Beau Canada's production in 1999 averaged 15,948 boe/d, down eight percent from 1998. A portion of the variance is related to the disposition of assets in late 1998, which negatively impacted 1999 production. The disposition proceeds were used to fund part of a strategic acquisition made in early 1998. Additionally, low oil prices in early 1999 resulted in the Company shutting in significant heavy oil production early in the year.

In the first quarter of 2000, production averaged 15,714 boe/d, up from the same quarter in 1999, but down slightly from the previous quarter. The disposition of the Helmet property early in the quarter and facility related downtime at Peggo contributed to the variance from the previous quarter.

Gas production averaged 89.1 mmcf/d in 1999, down two percent from 1998. Production additions were made throughout 1999, but did not offset the impact of dispositions and normal production declines. Increases in gas production did occur in the second quarter of 1999 with gas wells tied-in from the winter drilling programs in the Peggo and Chinchaga areas of northeastern British Columbia and the Shiningbank area of west central Alberta. Later in the third and fourth quarters, additional gas and NGLs production was added from successful drilling in the Cranberry and Gilby areas of western Alberta.

Gas production in the first quarter of 2000 averaged 76.2 mmcf/d, down 15 percent from the same quarter in 1999 and nine percent from the previous quarter. This variance is largely the result of a loss of approximately 4 mmcf/d associated with the disposition of the Helmet property early in the quarter, as well as facility downtime.

Oil production averaged 7,038 bbls/d in 1999, down 15 percent from 1998. The decrease in oil production was the result of property dispositions in late 1998, the curtailment of production and the deferral of oil projects in the first half of 1999 in response to weak oil prices. Oil and NGLs production averaged 6,529 bbls/d in the first half of 1999. During this period, the Company shut-in approximately 1,500 bbls/d of heavy oil production and deferred its oil exploration and development programs. With improving oil prices in the third quarter, we brought on production from shut-in heavy oil wells and commenced low risk development drilling, increasing oil and NGLs production to an average of 7,763 bbls/d in the fourth quarter.

Oil and NGLs production in the first quarter of 2000 averaged 8,095 bbls/d, up 26 percent from the same quarter in 1999 and four percent from the previous quarter. This increase was made despite the loss of 180 bbls/d of heavy oil production associated with the Court Bakken Unit disposition made in late 1999.

We are currently producing 93 mmcf/d of gas and 7,400 bbls/d of oil and NGLs. This production is subsequent to the reduction of approximately 2.5 mmcf/d of gas and 600 bbls/d of oil and NGL production associated with the sale of the Bantry assets in early May 2000. Gas volumes are currently up 22 percent from the first quarter average as the Peggo facility modifications have been completed and gas production from the winter drilling programs at Peggo, South Hamburg and Cranberry have been brought onstream.

DRILLING

The Company drilled 74 (54.7 net) wells in 1999 with a 75 percent success rate, resulting in 26 (18.8 net) gas wells, 31 (22.0 net) oil wells and 17 (13.9 net) D & A wells. Thirty-four (25.0 net) wells were drilled in the gas fairway in west central Alberta, northwestern Alberta and northeastern British Columbia. The remaining 40 (29.7 net) wells were drilled in west central Saskatchewan and southern Alberta, almost exclusively for oil.

In the first quarter of 2000, Beau Canada participated in drilling 41 (32.2 net) wells with an 86 percent success rate. We drilled 16 (12.7 net) gas wells, 19 (15.1 net) oil wells and 6 (4.4 net) D & A wells. This activity occurred in northeastern British Columbia and western Alberta where we drilled 24 (18.1 net) wells primarily for natural gas and 17 (14.1 net) wells in west central Saskatchewan resulting in 16 (13.1 net) oil wells and 1 (1.0 net) D & A well.

SEISMIC AND LAND

In 1999 and in the first quarter 2000, Beau Canada acquired 3-D seismic programs over much of its undeveloped land holdings in the South Hamburg, Chinchaga and Cranberry areas. The Company has significant Slave Point production and undeveloped lands associated with each of these projects. The seismic was acquired to aid in the future exploration and development of these highly prospective lands.

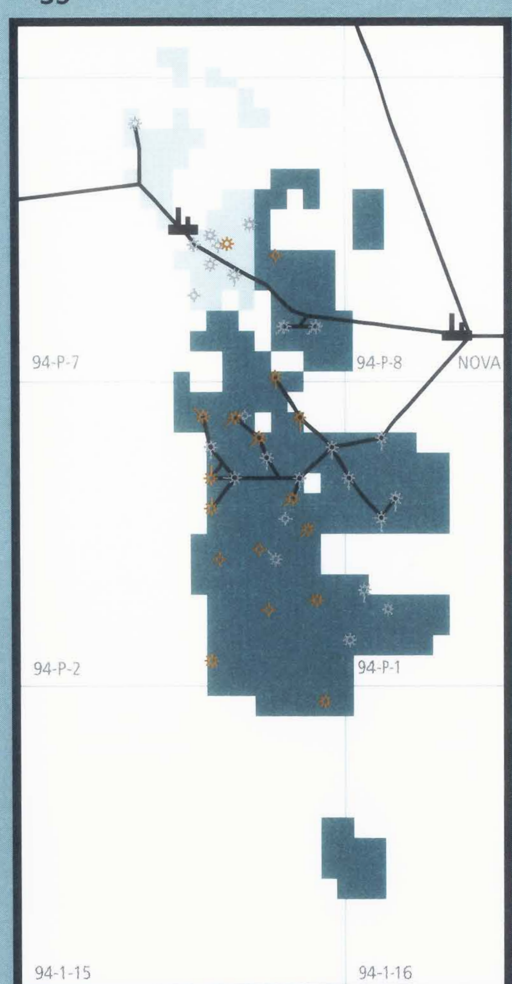
Our land position at year end 1999 was 196,100 net developed acres and 551,750 net undeveloped acres. More than 60 percent of our undeveloped land is located in the fairway extending from west central Alberta to northeastern British Columbia where we have been exploring for and developing natural gas reserves. Beau Canada's undeveloped land at March 31, 2000 was 505,575 net acres, down 46,175 acres from year end 1999. The change is due to land expiries, the loss of undeveloped land in association with the Helmet disposition and farmouts in northeastern British Columbia. In the first quarter we acquired 15,411 (4,623 net) acres in our South Hamburg project area bringing our total land holdings in the area to 33,993 (10,072 net) acres.

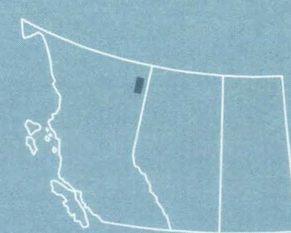
AREA OVERVIEWS

Peggo

The Peggo property is located in northeastern British Columbia. Beau Canada has 166,716 (144,106 net) acres of land and is currently producing 20 mmcf/d of gas and 100 bbls/d of NGLs from the Jean Marie formation. In 1999 we drilled 5 (4.5 net) horizontal gas wells and 1 (1 net) D & A well. Two (2 net) of the gas wells were tied-in in early 1999, and the remaining 3 (2.5 net) gas wells were tied-in the first quarter of 2000.

Peggo





Current Production	
Gas	20 mmcf/d
NGLs	100 bbls/d
Land Position	144,106 net acres
Productive Formations	Jean Marie / Slave Point
Working Interest	86%

1999 / 2000 Drilling · Existing Wells · Gas Plants · Lands Disposed

In the first quarter of 2000, Beau Canada drilled 4 (3.5 net) horizontal Jean Marie gas wells, 3 (3 net) strat test wells, 2 (2.0 net) D & A wells and shot an 86 km 2-D seismic program. Three (2.5 net) gas wells were tied-in prior to spring break-up. The three strat tests and 2-D seismic will help evaluate our undeveloped land position in the southern part of the land block for drilling 2000/2001. The Jean Marie is a low pressure gas reservoir, with the gas gathering system and compression facility delivering gas into the Nova system in Alberta.

In early 2000, Beau Canada disposed of substantially all of our interest in the Helmet property. Our production from Helmet at year end 1999, prior to the disposition, was 4 mmcf/d of gas from the Jean Marie and Slave Point formations. Included in the disposition was 23,725 net acres of land and our 10 mmcf/d gas plant. We drilled 1 (0.55 net) exploratory dry hole in late 1999/2000 on our remaining lands. We currently have 855 net acres remaining in the Helmet area, much of which has been covered by a 3-D seismic program. We will be re-evaluating the 3-D seismic in light of the recent drilling results to determine what potential remains for the prospect.

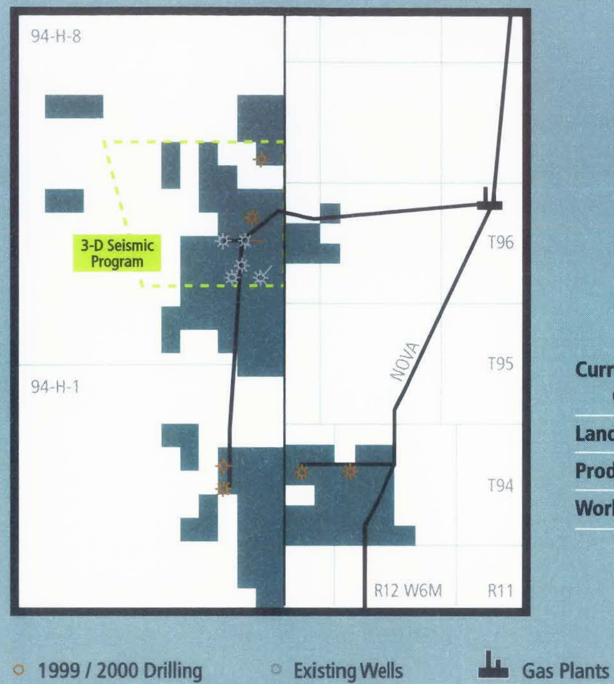
Chinchaga/South Hamburg

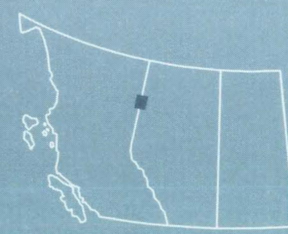
Beau Canada has been very active in these Slave Point properties that stretch across the British Columbia/Alberta border. Our land position can be broken into two areas: the Chinchaga area, in which the Company has 41,094 (27,486 net) acres of land; and the South Hamburg area, 8 kilometers to the south, with 33,993 (10,072 net) acres.

In early 1999 in the Chinchaga area, we acquired our partners' 50 percent interest. We drilled 2 (2 net) wells in 1999, resulting in 1 (1 net) Slave Point gas well and 1 (1 net) suspended well. The gas well was tied-in in early 1999 and production from the area is currently 2 mmcf/d. In the first quarter of 2000, we participated in drilling 1 (0.2 net) D & A well. We also shot a 154 km^2 3-D seismic program over a portion of our Chinchaga acreage. Preliminary interpretations show a number of potential Slave Point locations for the 2000/2001 drilling season.

One of the key assets in the Chinchaga property is the 100 percent Beau Canada owned 16 kilometre pipeline, which crosses the British Columbia/Alberta border and connects to the Nova infrastructure. The pipeline has capacity of 56 mmcf/d, with virtually all being utilized by gas coming from the Company's recent South Hamburg Slave Point discovery. The pipeline has a strategic benefit to Beau Canada in that it enabled production to be brought on stream in early 2000 from the discovery. We currently receive revenues from our partners in South Hamburg for pipeline usage.

Chinchaga / South Hamburg





Current Production	
Gas	**18 mmcf/d**
Land Position	**37,558 net acres**
Productive Formation	**Slave Point**
Working Interest	**50%**

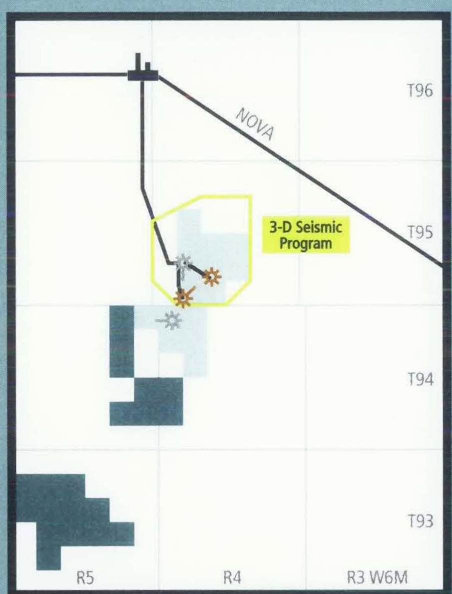
In the South Hamburg area, we currently have 33,993 (10,072 net) acres of land, much of which has been covered by 3-D seismic. In late 1999, together with our partners, we drilled 2 (0.6 net) successful exploratory Slave Point gas wells, one in British Columbia and one in Alberta. One of the discovery wells production tested at rates in excess of 31 mmcf/d and the second at rates of 3-4 mmcf/d. In early 2000, the Company participated in drilling another 2 (0.6 net) follow-up wells, resulting in 1 (0.3 net) gas well and 1 (0.3 net) D & A well. The gas wells have been tied-in and are on production. The South Hamburg production is relatively sweet high-pressure gas, flowing directly into Nova with low operating costs. Production from all wells commenced in April 2000 at combined rates exceeding 60 (18 net) mmcf/d in early May. Production from the area is currently limited by allowable to 53 (16 net) mmcf/d.

This major gas discovery will have a significant impact on Beau Canada's 2000 production, cash flow and reserve additions. These successes combined with our significant land holdings in the area position Beau Canada well for exploration and development activity for the remainder of 2000 and beyond.

Cranberry

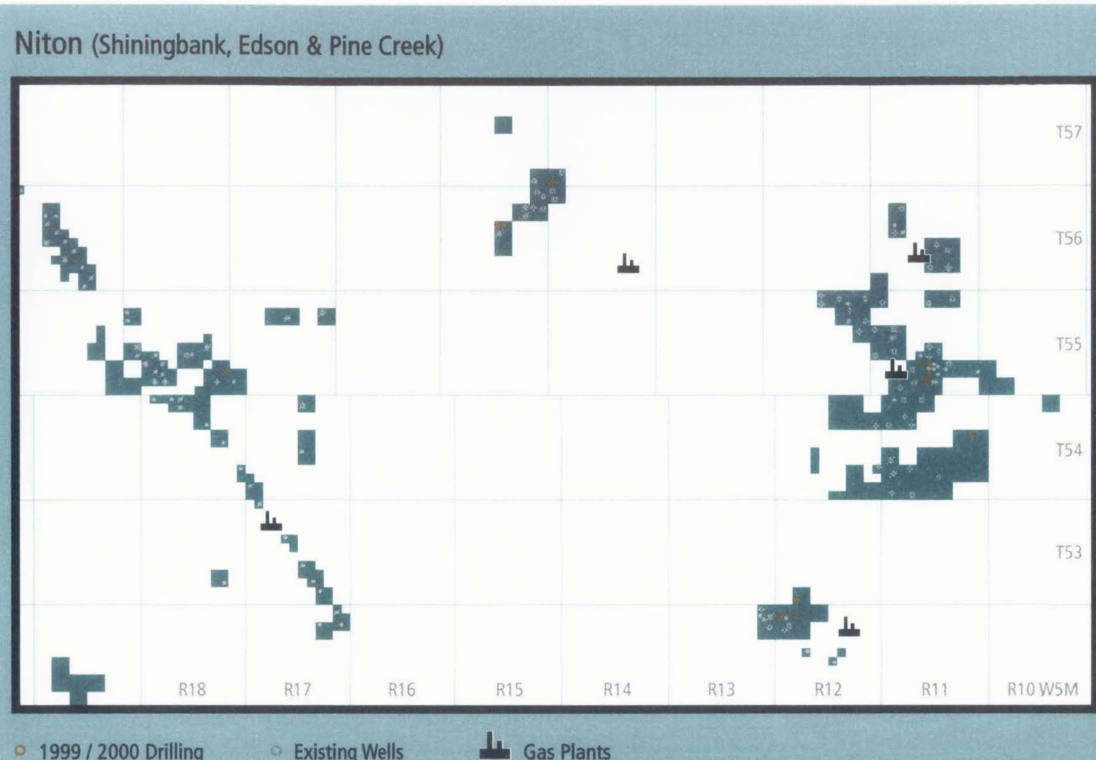
Beau Canada has 22,400 (13,227 net) acres of land in the Cranberry area of northwestern Alberta. We are producing 8 mmcf/d of gas and 400 bbls/d of NGLs from 3 (3 net) Slave Point gas wells. In 1999 the Company drilled 2 (2 net) Slave Point gas wells; one was brought on production in 1999 and the other was tied-in and brought on production in early 2000. In order to evaluate future drilling potential on our 100 percent owned lands in the Cranberry area, Beau Canada shot a 54 km^2 3-D seismic program in the first quarter of 2000. Preliminary interpretations show a number of potential locations that we plan to drill in 2000/2001. The remaining joint interest acreage is being evaluated for drilling prospects for the 2001/2002 winter drilling season.

Cranberry



Current Production	
Gas	8 mmcf/d
NGLs	400 bbls/d
Land Position	13,227 net acres
Productive Formation	Slave Point
Working Interest	58%

1999 / 2000 Drilling · Existing Wells · Gas Plants · 100% Lands



Current Production	
Gas	14 mmcf/d
Oil & NGLs	1,050 bbls/d
Land Position	64,445 net acres
Productive Formations	Various
Working Interest	75%

Niton

Beau Canada has 86,400 (64,445 net) acres in the Niton, Shiningbank, Edson, and Pine Creek areas of west central Alberta. Current production from the Niton area is 14 mmcf/d of gas and 1,050 bbls/d of light oil and NGLs. Along with the land position, the Company also has interests in five gas plants and associated infrastructure in the area. Production is from the Cardium, Basal Quartz, Gething, Rock Creek, and Elkton formations.

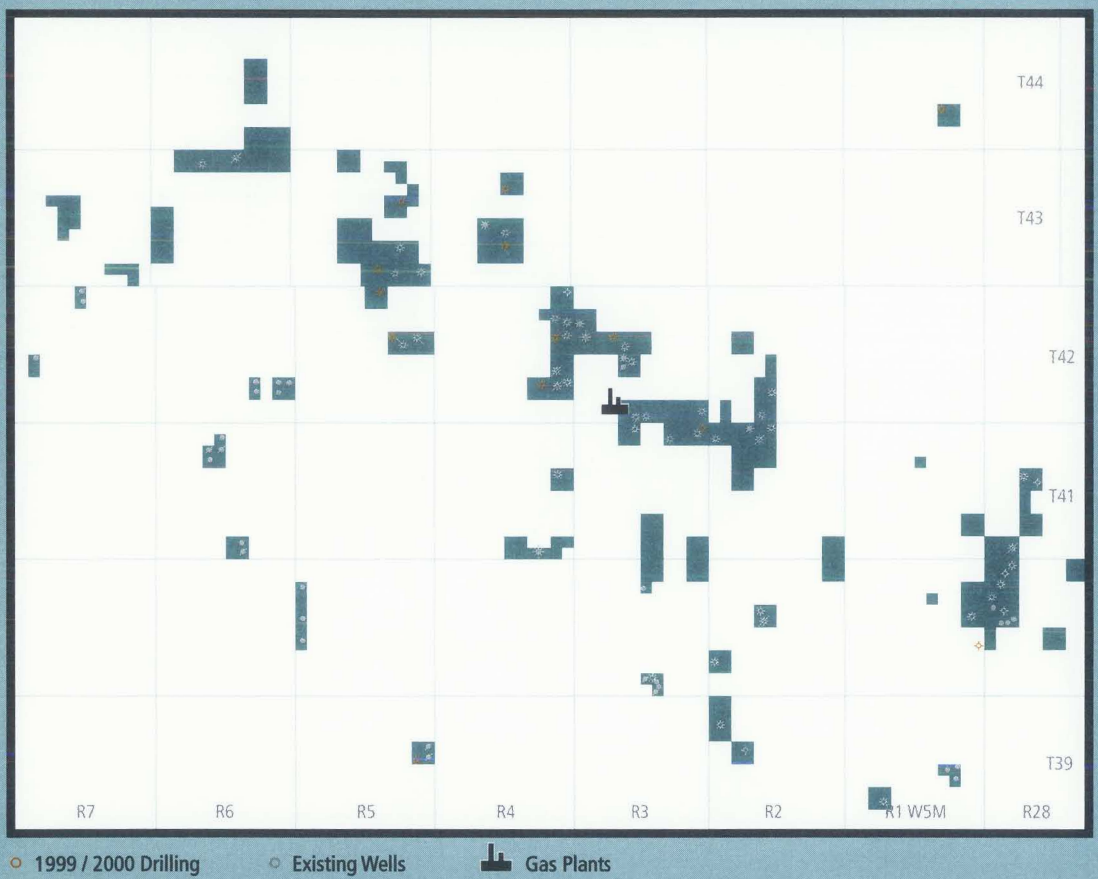
In 1999, Beau Canada drilled 6 (5.4 net) wells resulting in 3 (2.6 net) gas wells and 3 (2.8 net) D & A wells. The gas wells were tied-in in 1999. In the first quarter of 2000, we drilled 3 (2.0 net) oil wells, 2 (1.7 net) gas wells and 1 (1.0 net) D & A well.

Gilby/Gull Lake

Beau Canada has an interest in 69,652 (47,346 net) acres in the Gilby/Gull Lake area. Current production from the area is 21 mmcf/d of gas and 950 bbls/d of light oil and NGLs. The producing formations are Glauconitic, Basal Quartz, Jurassic and Pekisko. Beau Canada operates approximately 90 percent of our production in the area, along with two gas plants where we have a 100 percent and 74 percent ownership.

Activity in the Gilby/Gull Lake area in 1999 included drilling 6 (4.1 net) gas wells and 2 (1.6 net) D & A wells. Most of the drilling activity in the area occurred in the latter half of 1999, with production tied-in in 2000. Beau Canada drilled 3 (1.2 net) gas wells in the Gilby area in the first quarter of 2000.

Gilby / Gull Lake



Current Production	
Gas	21 mmcf/d
Oil & NGLs	950 bbls/d
Land Position	47,346 net acres
Productive Formations	Various
Working Interest	68%

West Central Saskatchewan

Beau Canada has 111,893 (89,569 net) acres of land in west central Saskatchewan. Production from the area is currently 3,900 bbls/d of heavy oil and 5 mmcf/d of gas. In early 1999, we had approximately 1500 bbls/d of heavy oil shut-in due to low oil prices. With improving prices in the latter part of the year, all this shut-in production was brought back on stream. We responded to the improved pricing by drilling 35 (24.7 net) wells, resulting in 25 (16.5 net) oil wells, 2 (1.7 net) gas wells and 8 (6.5 net) D & A wells in 1999. This drilling activity added 1,000 bbls/d of production, averaging 355 bbls/d for the year. In the first quarter of 2000, Beau Canada drilled 16 (13.1 net) oil wells and 1 (1.0 net) D & A well. Some of these wells are currently on production while others are awaiting completion and equipping.

Late in 1999, we disposed of our 8.2 percent interest in the Court Bakken Unit No. 1. Our production from the Unit averaged 180 bbls/d of oil at the time of the disposition.

Much of the drilling activity in west central Saskatchewan was concentrated in two areas, Low Lake and Baldwinton.

Low Lake

Beau Canada has interests in 7,917 (7,478 net) acres in the Low Lake area. We currently produce 780 bbls/d of heavy oil from the Waseca formation. We drilled 12 (12.0 net) wells in 1999, resulting in 10 (10.0 net) oil wells and 2 (2.0 net) D & A wells. The drilling added 450 bbls/d of production. Operating costs for the property are approximately $3.50/bbl, providing attractive netbacks.

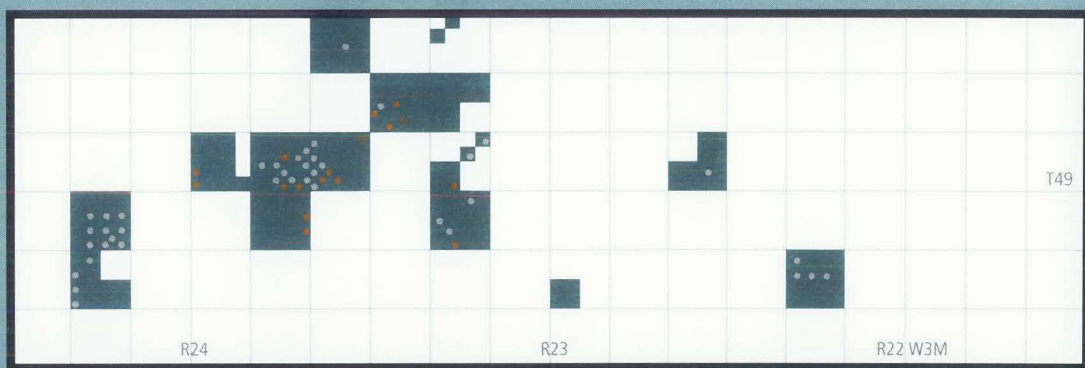
We drilled 5 (5.0 net) wells resulting in 4 (4.0 net) oil wells and 1 (1.0 net) D & A well during the first quarter of 2000, some of which were stepout and exploration locations, expanding existing pool boundaries and leading to new pool discoveries.

Baldwinton

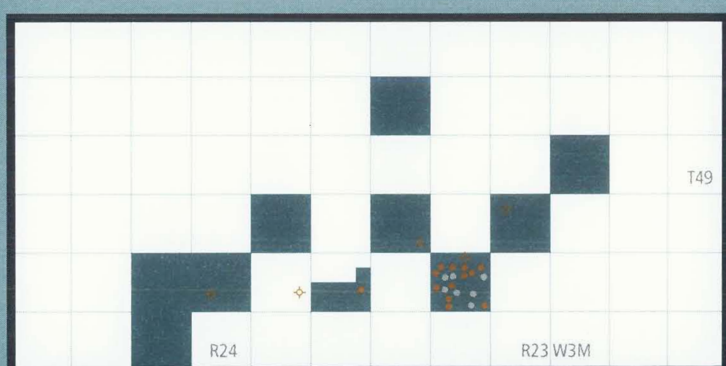
In the Baldwinton area, we have 6,120 (4,921 net) acres and are currently producing 600 bbls/d of heavy oil from the Waseca formation. In 1999, we drilled 15 (7.7 net) wells resulting in 11 (5.2 net) oil wells and 4 (2.5 net) D & A wells. The drilling activity added 400 bbls/d of production. The Baldwinton property also has low operating costs, at approximately $4.00/bbl, giving attractive netbacks.

In the first quarter of 2000 we drilled 1 (0.5 net) oil well.

Low Lake



Baldwinton



1999 / 2000 Drilling   Existing Wells

Current Production	
Oil	1,380 bbls/d
Land Position	12,400 net acres
Productive Formations	Various
Working Interest	87%

The discussion and analysis and financial statements that follow are for the quarter ended March 31, 2000 and the year ended December 31, 1999.

REVENUE

First quarter 2000 oil and gas revenues at $37.3 million were up 45 percent from the same period of 1999, due to improved oil and liquids prices. The Company had oil and gas revenues before royalties of $126.8 million in 1999 (1998-$108.9 million), representing a 16 percent increase from the previous year. Increased product prices more than offset reduced production.

First Quarter

	Revenue		Change relating to:		
(millions)	**2000**	1999	Sales Volume	Price	Total Change
Revenue					
Gas	**$ 16.1**	$ 18.6	$ (2.7)	$ 0.2	$ (2.5)
Oil and NGLs	**21.2**	7.1	1.9	12.2	14.1
	37.3	25.7	$ (0.8)	$ 12.4	11.6
Other	**0.1**	0.0			0.1
	$ 37.4	$ 25.7			$ 11.7

Year Ended December 31

	Revenue		Change relating to:		
(millions)	**2000**	1999	Sales Volume	Price	Total Change
Revenue					
Gas	**$ 76.0**	$ 62.8	$ (1.4)	$ 14.6	$ 13.2
Oil and NGLs	**50.8**	46.1	(7.5)	12.2	4.7
	126.8	108.9	$ (8.9)	$ 26.8	17.9
Other	**1.2**	16.8			(15.6)
	$ 128.0	$ 125.7			$ 2.3

Gas prices received for the first quarter of 2000 were comparable to those for the same period in 1999, while gas production at 76.2 mmcf/d decreased 15 percent from first quarter 1999. The reduced gas production is due largely to the disposition of the Company's Helmet property in January, 2000 and downtime associated with facilities at Peggo, both in northeastern British Columbia. The combined effect resulted in a reduction of 8 mmcf/d for the quarter compared to last year. Other quarter to quarter reductions related to field declines. Gas production in the second quarter of 2000 has increased to levels comparable to 1999 as gas discovered and developed over the winter drilling season has been brought onstream. Oil and liquids prices received are up 135 percent over 1999 levels to average $28.81. This was as a result of improved world oil prices. Production at 8,095 bbl/d increased 26 percent over 1999, due to heavy oil property brought on production through late 1999 as prices improved from depressed first quarter 1999 levels.

Gas volumes averaged 89.1 mmcf/d in 1999, a two percent decrease from the previous year's volumes. Production decreases in oil were as a result of planned dispositions of properties in late 1998 in order to fund a mid-1998 property purchase. Oil production was further reduced by the shut-in of 1,500 bbls/d of heavy oil production in early 1999 due to low oil prices. Later in 1999, production was gradually brought back on as prices improved. Oil and NGL volumes for 1999 averaged 7,038 bbls/d, down 15 percent from the previous year. Of the $104.4 million in net revenue, $61.6 million (59.1 percent) was gas revenue, $41.6 million (39.8 percent) was oil and NGL revenue, and the remaining $1.2 million (1.1 percent) was technology service revenue and interest income. Of the net revenue, approximately 65.6 percent was generated from Alberta properties, 14.3 percent from B.C. properties, and 19.0 percent from Saskatchewan properties with the remainder being other income. Of the oil and NGL revenue, 36.8 percent was from light and medium oil, 30.9 percent from NGLs and 32.3 percent from heavy oil.

The Company realized gains of $9.3 million on the sale of its Alliance/Fort Chicago investment and $3.2 million (after minority interest) through the Company's subsidiary, Genoil Inc., for the sale of non-core offshore acreage in the Republic of Cuba in 1998. These gains were included in other income.

During the first quarter of 2000, the Company's revenues were $4.1 million lower than amounts received for products due to the effect of price hedges which were entered into to protect against downside price risks.

During 1999, the Company's revenues were $7.0 million lower (1998 – $7.9 million higher) than amounts received for products due to the effect of price hedges which were entered into to protect against downside price risks.

Quarterly Production

	1998				**1999**				**2000**
	Q1	Q2	Q3	Q4	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**
Gas (mmcf/d)	56.7	109.7	102.4	94.9	**90.1**	**93.8**	**89.2**	**83.4**	**76.2**
Oil & NGLs (bbls/d)	8,373	9,095	9,079	6,675	**6,418**	**6,638**	**7,314**	**7,763**	**8,095**
BOE/d (10:1)	14,044	20,067	19,314	16,164	**15,431**	**16,019**	**16,233**	**16,099**	**15.714**
BOE/d (6:1)	17,824	27,382	26,138	22,491	**21,439**	**22,273**	**22,178**	**21,656**	**20,793**

Current gas production has increased to 93 mmcf/d; oil production is at 7,400 bbl/d. Gas production continues to increase as first quarter drilling is tied in and brought on full production. Current oil and gas production shows the effect of the Bantry sale of 600 bbl/d of oil and liquids and 2.5 mmcf/d of gas production.

ROYALTIES

Royalties for the quarter ended March 31, 2000 averaged 23 percent of sales, up from 17 percent in 1999. Higher oil prices and higher reference prices for calculation of gas royalties both attract higher royalty burdens, accounting for the overall increase in the effective royalty rate.

Royalties for 1999 totalled $23.6 million (19 percent of revenues) compared to $17.0 million (16 percent of revenues) a year earlier. The properties acquired through the purchase of a private company in 1998 bear Crown royalties at a rate of approximately 20 percent, resulting in the increase in the average royalty rate.

OIL AND GAS EXPENSES

Operating expenses were $4.70 per boe (10:1) in the first quarter, similar to the $4.65 per boe recorded in the fourth quarter of 1999. Operating costs for the first quarter of 1999 were $4.19 per boe. Higher cost heavy oil production brought on by 2000 to take advantage of higher product prices accounts for much of the increase in per barrel costs.

Oil and gas operating expenses for the year ended December 31, 1999 totalled $25.5 million, or $4.38 per boe (10:1), compared to $26.4 million or $4.16 per boe in 1998. Operating netbacks in 1999 averaged $13.35/boe, up 30 percent from $10.30/boe in 1998. Increased gas, oil and liquids prices more than offset higher royalty rates and operating costs per unit.

Netbacks per BOE

	Three months ended March 31				Year ended December 31			
	2000		1999		1999		1998	
	(10:1)	(6:1)	(10:1)	(6:1)	(10:1)	(6:1)	(10:1)	(6:1)
Revenue	$26.07	$19.70	$18.47	$13.29	$21.78	$15.87	$17.13	$12.70
Royalties	6.08	4.59	3.13	2.26	4.05	2.95	2.67	1.98
Operating expenditures	4.70	3.55	4.19	3.02	4.38	3.19	4.16	3.09
Netback	15.29	11.56	11.15	8.01	13.35	9.73	10.30	7.63
General & administrative	1.13	0.85	1.26	0.91	1.09	0.80	0.97	0.72
Interest & other	2.28	1.72	1.98	1.43	2.45	1.79	1.96	1.46
Taxes	0.46	0.35	0.28	0.20	0.27	0.20	0.22	0.16
Cash flow	11.42	8.64	7.63	5.47	9.54	6.94	7.15	5.29
Depletion & depreciation	8.46	6.40	8.07	5.81	11.44	8.33	6.70	4.97
Site restoration	0.45	0.34	0.22	0.16	0.34	0.25	0.20	0.15
Future income taxes	1.06	0.80	0.32	0.23	(0.43)	(0.31)	0.31	0.23
Non-cash losses (gains)	–	–	–	–	–	–	(2.42)	(1.80)
Minority interest in Genoil	–	–	–	–	(0.99)	(0.72)	0.41	0.30
Income (loss) from continuing operations	1.45	1.10	(0.98)	(0.73)	(0.82)	(0.61)	1.95	1.44
Income (loss) from discontinued operations	(7.30)	(5.52)	(0.03)	(0.01)	–	–	–	–
Net income (loss)	(5.85)	(4.42)	(1.01)	(0.74)	(0.82)	(0.61)	1.95	1.44

INTEREST EXPENSE

Interest expense was $3.4 million for the first quarter of 2000, up from $2.8 million for the same period last year. Higher interest rates on higher average debt levels accounted for this increase.

The Company incurred total interest expense of $13.2 million in 1999 compared to $13.9 million for the previous year. Higher average debt levels in 1998 were needed to finance the 1998 capital expenditure program, including acquisitions. The debt levels in 1999 were lowered from 1998 levels due to the disposition of $56.0 million of Canadian properties in the fourth quarter of 1998. The average interest rate on long-term debt was 6.6 percent in 1999 and 6.4 percent in 1998.

GENERAL AND ADMINISTRATIVE

General and administrative expenses were $1.6 million for the three-month period in 2000 compared with $1.8 million for the first quarter of 1999.

General and administrative expenses for 1999 were $6.4 million ($1.09/boe) compared with $6.2 million ($0.97/boe) in 1998. The increase reflects increased staffing and salary levels. G & A expenses of $2.3 million were capitalized compared to $2.0 million in 1998.

First Quarter

		2000			1999	
($ thousands)		**$/boe (10:1)**	**$/boe (6:1)**		$/boe (10:1)	$/boe (6:1)
Total G & A	**2,922**	**$ 2.04**	**$ 1.54**	2,768	$ 1.99	$ 1.44
Overhead recoveries	**(872)**	**(0.61)**	**(0.46)**	(478)	(0.34)	(0.25)
	2,050	**1.43**	**1.08**	2,290	1.65	1.19
Capitalized G & A	**(433)**	**(0.30)**	**(0.23)**	(540)	(0.39)	(0.28)
Reported G & A expense	**1,617**	**1.13**	**0.85**	1,750	1.26	0.91

Year Ended December 31

		1999			1998	
($ thousands)		**$/boe (10:1)**	**$/boe (6:1)**		$/boe (10:1)	$/boe (6:1)
Total G & A	**10,435**	**$ 1.79**	**$ 1.31**	10,452	$ 1.65	$ 1.22
Overhead recoveries	**(1,774)**	**(0.30)**	**(0.22)**	(2,332)	(0.37)	(0.27)
	8,661	**1.49**	**1.09**	8,120	1.28	0.95
Capitalized G & A	**(2,294)**	**(0.40)**	**(0.29)**	(1,970)	(0.31)	(0.23)
Reported G & A expense	**6,367**	**1.09**	**0.80**	6,150	0.97	0.72

DEPLETION, DEPRECIATION & SITE RESTORATION

Depletion and depreciation expenses at $12.1 million ($8.46/boe, 10:1) for the quarter ended March 31, 2000 have increased from $11.2 million ($8.07 per boe) in 1999. Higher reserve addition costs in 1999 and 2000 combined to create this increase. Site restoration expenses at $0.6 million (first quarter 1999 – $0.3 million) for the quarter have increased over 1999 levels due to the reallocation of anticipated salvage values to the depletion calculation in 2000 from the site restoration calculation in the first two quarters of 1999.

Depletion and depreciation increased $4.9 million to $47.5 million ($8.15/boe 10:1) during 1999 from $42.6 million ($6.70/boe) in 1998. The increase in depletion and depreciation on a per boe basis is caused by downward reserve revisions and higher reserve addition costs in 1999. A write down of Cuban costs of $19.1 million was recorded as reserves were not discovered in Cuba. The net effect on income after taxes and the minority interest share in the write down was $7.2 million. The Company has recorded a $2.0 million ($0.34/boe) site restoration provision in 1999 as compared to $1.3 million ($0.20/boe) in 1998. The increase is due to the reallocation of anticipated salvage values to the depletion calculation in the last half of 1999 from the site restoration calculations in prior quarters.

INCOME TAXES

In the first quarter of 2000 the effective tax rate was 42 percent on continuing operations. Income tax expense of $0.5 million was recorded on a loss from continuing operations of $0.9 million in the first quarter of 1999. This was as a result of the application of the deferral method of accounting for income taxes in the first quarter of 1999. Had the liability method of accounting for income taxes (adopted in the second quarter of 1999, effective January 1, 1999) been adopted in the first quarter of 1999, a recovery of taxes on the first quarter loss would have been recorded.

In 1999, the Company recorded a future income tax reduction of $2.5 million. The effective tax rate was 19 percent on pre-tax losses. This unusually low effective tax rate was a result of no benefit being recorded on losses in the technology services subsidiaries.

At year end the Company had unused tax pools of approximately $310 million. The COGPE portion of these pools is approximately $17 million and FEDE is approximately $22 million. The balance of the pools are CEE, CDE, UCC and tax loss carry forwards. Approximately $60 million of these pools are currently the subject of a review by taxation authorities. The Company is of the opinion that such costs and losses will be available and the benefit recognized to date (approximately $19 million as a future tax expense reduction) will be realized. The Company does not expect to be cash taxable in the near term. The extent of future taxes will depend on product prices and exploration and development activities.

In 1999 the Company changed its method of accounting for income taxes. Effective January 1, 1999 the liability method was adopted; prior thereto, the Company followed the deferral method. The new method was applied retroactively without restatement of prior period financial statements. At January 1, 1999 the future income tax liability was increased by $37.6 million and retained earnings was decreased by $37.6 million. These adjustments were a result of the recognition of future taxes where the tax basis of acquired companies was less than the acquisition cost. The effect of the change in accounting was to reduce the loss by $1.8 million ($0.02 per share) for the year ended December 31, 1999.

DISCONTINUED TECHNOLOGY SERVICES AND CUBAN OPERATIONS

During 1999 the Company entered into the technology services business through its subsidiary, Genoil Inc., and also ceased oil and gas operations in Cuba in its subsidiary Genoil Inc. Commercial viability in the technology services business has not yet been achieved. The future viability of the technology services operation will depend on the ability of Genoil Inc. to obtain additional financing and attain profitable operations.

In May 2000 the Company announced its intention to dispose of its interest in Genoil Inc. (including Genoil's 100 percent subsidiary, CE3 Technologies Inc.). The operations of Genoil (including technology services and Cuban oil and gas operations) have accordingly been reflected as discontinued operations. A loss of $10.4 million on discontinued operations has been recorded for the first quarter of 2000, comprising operating losses of $2.4 million, estimated losses until disposition of $2.0 million and a writedown of the assets of the discontinued operations of $6.0 million. 1999 technology services contributed negative cash flow from operations of $2.3 million and a loss of $3.3 million.

LAND

The Company's total undeveloped land holdings increased 11 percent during 1999. During 1999 the Company increased its undeveloped land holding in its strategic core areas.

Canadian Land Holdings

	Developed		Undeveloped		Total Acres	
(December 31, 1999)	Gross	Net	Gross	Net	Gross	Net
Alberta	327,393	143,778	307,570	213,304	634,963	357,082
British Columbia	54,495	32,576	307,339	257,359	361,834	289,935
Saskatchewan	34,490	19,742	89,306	81,086	123,796	100,828
Totals	416,378	196,096	704,215	551,749	1,120,593	747,845

CAPITAL EXPENDITURES

The Company spent $45.6 million during the first quarter of 2000; well over half of the Company's current exploration and production budget was spent in the first quarter as the winter program was completed.

The Company added $101.6 million to property, plant and equipment in 1998, net of dispositions.

Capital Expenditures First Quarter

(thousands)	**2000**	1999
Canada		
Drilling and tie-ins	**$ 38,057**	$ 30,926
Seismic	**3,256**	1,222
Facilities	**992**	–
Acquisitions	–	433
Lands	**2,152**	1,105
Producing property purchases	**503**	3,826
Corporate	**673**	1,427
Total	**45,633**	38,939
Dispositions	**(12,039)**	–
Net Capital Expenditures – Continuing Operations	**$ 33,594**	$ 38,939

Capital Expenditures Year Ended December 31

(thousands)	1999	1998
Canada		
Drilling, tie-ins and geological & geophysical	**$ 60,403**	$ 61,821
Plant and equipment	**13,866**	7,008
Acquisitions	**2,246**	100,132
Land	**9,032**	9,839
Producing property purchases	**11,189**	3,749
Other	**3,204**	2,831
Total	**99,940**	185,380
Dispositions	**(3,900)**	(56,368)
Net – Canada	**96,040**	129,012
Cuba		
Acquisitions (net of minority interest)	**433**	3,300
Capital expenditures	**5,175**	12,017
Total	**5,608**	15,317
Dispositions	–	(10,080)
Net – Cuba	**5,608**	5,237
Net Capital Expenditures	**$101,648**	$ 134,249

Drilling Results First Quarter 2000

(Wells)	Gross	Net
Development	14	10.8
Exploration	27	21.4
Total	41	32.2
Gas	16	12.7
Oil	19	15.1
Dry & abandoned	6	4.4
Total	41	32.2
Success rate	85%	86%

Drilling Results Year Ended December 31, 1999

(Wells)	Gross	Net
Development	37	25.0
Exploration	37	29.7
Total	74	54.7
Gas	26	18.8
Oil	31	22.0
Dry & abandoned	17	13.9
Total	74	54.7
Success rate	77%	75%

RESERVES

Beau Canada's established (proven plus risked probable) reserves were 64.1 mmboe's at year end 1999, up five percent from the previous year. Established natural gas reserves were 346 bcf, down approximately 9 bcf or two percent from the previous year. Although the Company added 73 bcf of established gas reserves through discoveries, negative revisions of 52 bcf and production of 33 bcf resulted in the decrease in established gas reserves at year end. Proven gas reserves were 286 bcf at year end, down 12 bcf or four percent from the previous year. The Company added 60 bcf of proven gas reserves through discoveries while negative revisions and production accounted for 43 bcf and 33 bcf, respectively.

Oil and NGLs established reserves were 29.5 mmbbls at year end 1999, up 15 percent from the previous year. Strong oil prices in the latter half of 1999 encouraged Beau Canada to explore and exploit its oil properties resulting in significant reserve additions. The Company added 7.1 mmbbls of established oil and NGLs reserves while incurring negative revisions of 0.4 mmbbls., dispositions of 0.3 mmbbls and production of 2.6 mmbbls. Similarly, the proven oil and NGLs reserves increased to 25.2 mmbbls, an increase of 15 percent from 1998 year end values.

The cost of reserves added in Canada for 1999 was $9.75/boe ($9.86/boe in 1998) for established reserves and $10.96/boe ($16.37/boe in 1998) for proven reserves. The Company's three-year average cost of reserve additions is $8.50/boe for established reserves and $10.75/boe for proven reserves.

In the first quarter of 2000, gas discoveries were made in the Jedney and Aitken areas of northeast British Columbia which adds to the Company's reserves. In the South Hamburg area, well performance is exceeding expectations and a significant upward reserve revision is likely. In addition, as the Company continues to explore and develop its large undeveloped land position, significant reserves will be added at a low cost since most of the investment in land, seismic and pipeline infra-structure was incurred in late 1999 and early 2000.

In the first quarter of 2000, well drilling in west central Saskatchewan resulted in new pool discoveries and extensions adding to the Company's reserves. Although the Company has added significant reserves in the first quarter, property dispositions at Helmet and Bantry in the quarter will have a negative impact on reserve growth.

Gas, Oil & NGLs Reserves

(Gilbert Laustsen Jung, January 1, 2000) *

	Natural Gas (bcf)	Oil (mmbls)	NGL (mmbls)
Proven reserves			
Producing	198	10,463	5,571
Non-producing	88	7,876	1,300
Total proven	286	18,339	6,871
Probable reserves	121	6,077	2,421
Total proven and probable reserves	407	24,416	9,292
Total proven and risked probable reserves ** Jan. 1/00	346	21,378	8,082
Total proven and risked probable reserves ** Jan. 1/99	355	16,494	9,123

* *Reserve estimates include natural gas and natural gas liquids dedicated to an exclusive long term gas marketing arrangement at the Bantry gas plant.*

** *Probable reserves risked at 50%*

The Company has commissioned an update to the reserve report, to be effective July 1, 2000. This report will be available by September 30, 2000.

Reserve Reconciliation

	Proven & probable		Proven		Established	
	Oil & NGLs MBBLS	Gas BCF	Oil & NGLs MBBLS	Gas BCF	Oil & NGLs MBBLS	Gas BCF
Reserves at January 1, 1999	29,252.7	412.3	21,980.0	298.2	25,616.4	355.3
Discoveries & additions	8,197.2	85.2	6,084.8	60.3	7,141.0	72.7
Revisions (to previous estimates)	(849.9)	(60.8)	(36.3)	(42.9)	(443.1)	(51.9)
Acquisitions & dispositions	(323.2)	2.7	(249.3)	2.7	(286.3)	2.7
Production	(2,568.8)	(32.5)	(2,568.8)	(32.5)	(2,568.8)	(32.5)
Reserves at January 1, 2000	33,708.0	406.9	25,210.4	285.8	29,459.2	346.3

Net Asset Value (January 1, 2000)

Future cash flow from reserves discounted at	10%		15%	
(millions)	Proven & Probable	Proven	Proven & Probable	Proven
Proven producing	$ 336	$ 336	$ 292	$ 292
Proven non-producing	105	105	82	82
Total proven	441	441	374	374
Probable	112	–	83	–
Total company reserve value *	553	441	457	374
Undeveloped land value	45	45	45	45
Geophysical data value	20	20	20	20
Site restoration (net of salvage)	(10)	(10)	(10)	(10)
Working capital deficiency excluding debt	(25)	(25)	(25)	(25)
Hedge adjustment **	(30)	(30)	(28)	(28)
Long term debt	(204)	(204)	(204)	(204)
Term equity	(42)	(42)	(42)	(42)
Net asset value	$ 307	$ 195	$ 213	$ 130
Per share (91,942,913 shares)	$ 3.34	$ 2.12	$ 2.32	$ 1.41
Proven and risked probable per share	$ 2.73		$ 1.87	

* *Values include adjustments for the company's transportation contracts.*

** *Adjustments for financial and physical fixed price contracts.*

FINANCIAL POSITION

First quarter capital expenditures were financed with cash flow, debt and working capital. The working capital deficiency increased to $44.0 million, excluding discontinued operations, up from $21.0 million in the first quarter of last year. The sale of the Bantry plant and associated oil wells for $23 million in May 2000 improved the working capital deficiency.

During the first quarter of 2000, the working capital deficiency of the company increased substantially as capital expenditures on oil and gas and technology services exceeded first quarter cash flow. In May 2000 property sales were completed, reducing the working capital deficiency by $24 million.

On December 31, 1999, the Company had $202.7 million in long term debt, an increase of $40.2 million over 1998. The Company has fixed the interest rate at approximately 5.66 percent (excluding bank margins) on $110 million of its indebtedness over an average term of approximately two years.

The Company has financed its growth by utilization of reserve based revolving lines of credit and by accessing the equity market. At December 31, 1999 the Company had 91.9 million shares outstanding at a market capitalization of $164 million.

In May 2000, the Company agreed with Enron Capital & Trade Canada to extend the term equity through a subordinated non-convertible debenture. This successor instrument will have a lump sum principal and interest payment of $45.4 due December 12, 2000. The Company may pay accrued interest and principal before maturity.

Term equity in the amount of $36.6 million was issued June 11, 1998 under the following terms:

- Bears interest at 7.5 percent. Interest is not payable until June 11, 2000.
- Is repayable in full with interest accrued over the life of the instrument on June 11, 2000 by the issue of shares based on the then market price or by payment of cash.
- The Company had the option to prepay the instrument (including accrued interest) in cash at any time before June 11, 2000.

In connection with the issue of the term equity, the Company granted warrants to purchase 7,900,000 common shares at $2.80 per share. The warrants expired June 10, 2000. Had the warrants been exercised, the proceeds were to have been used to repay a portion of the term equity.

BUSINESS RISKS

The oil and gas industry is subject to numerous risks, including commodity price fluctuations, interest rate fluctuations, exchange rate fluctuations, environmental concerns and uncertainty with respect to the success of future drilling. Beau Canada has adopted a policy of reducing and managing those risks which are controllable.

The Company is exposed to fluctuations in commodity prices. The risks associated with these fluctuations are managed through:

- Financial instruments which have the net effect of delivering a hedged price to the Company,
- Physical contractual arrangements to deliver products for fixed prices or for floating, index based prices, or
- Choices as to what physical markets can be accessed, through contractual transportation arrangements.

The Company has fixed the differential between the AECO benchmark gas prices and a fixed price, effectively contracting the price received through financial instruments and physical fixed price contracts as follows:

MARKETING CONTRACTS

In place March 31, 2000

Type	Term	Quantity	Price
Financial	Present to October 2000	30 mmcf/d	$2.3767/G
Financial	Present to October 2000	5 mmcf/d	US$2.41/mmbtu
Financial	November 2000 to March 2001	20 mmcf/d	$2.70/GJ
Financial	April 2001 to October 2001	20 mmcf/d	$2.375/GJ
Physical	Present to October 2004	10 mmcf/d	$2.65/GJ
Physical	April 2001 to March 2004	25 mmcf/d	AECO minus US$0.195
Physical	Present to April 2009	3.9 mmcf/d	$1.87/GJ with an annual escalation

The Value of these financial and physical fixed price contracts were not included in the Gilbert Laustsen Jung 1999 year end reserves report but are included in the net asset value calculation.

The Company has entered into hedges to minimize price risk. As commodity prices continue to rise, these hedges have capped a portion of the revenue that the Company would have realized had the hedges not been in place. In June, 2000, certain hedges were monetized to allow the Company to participate in these rising prices. There are risks that should prices fall, the prices realized would be lower than the original hedges. Although we believe this risk to be very small, we are prepared to re-enter into fixed price hedges to eliminate this risk, once prices have reached the $5.00/GJ to $6.00/GJ range. The above noted transactions were replaced with the following effective July 1, 2000:

Type	*Term*	*Quantity*	*Price*
Financial	*Present to October 2000*	*20 mmcfld*	*$2.41/GJ*
Financial	*November 2000 to March 2001*	*10 mmcfld*	*$2.70/GJ*
Financial	*April 2001 to October 2001*	*10 mmcfld*	*$2.375/GJ*
Physical	*Present to October 2004*	*5.5 mmcfld*	*$2.65/GJ*
Financial	*Present to October 2000*	*10 mmcfld*	*AECO less $3.3325/GJ*
Financial	*November 2000 to March 2001*	*10 mmcfld*	*AECO less $2.9425/GJ*
Financial	*April 2001 to October 2001*	*10 mmcfld*	*AECO less $3.2675/GJ*
Physical	*Present to October 2004*	*5 mmcfld*	*AECO less $2.0350/GJ*

In June 2000 the Company produced approximately 70 mmcf/d which receives floating prices, except when modified by the financial or physical contract. 30.5 mmcf/d of the production will effectively enjoy fixed prices until October 31, 2000, when only 15.5 mmcf/d will be hedged into fixed prices. Other production will receive lower than market prices due to the hedges outlined above but will not be capped, as are the fixed price contracts.

2000 barrels per day of oil production has financial instruments in place, creating a collar which at current prices effectively caps the WTI price on this production at US$20.85 until the end of 2000. No oil price instruments are in place beyond that time frame.

The Company also has contracts which include transportation to various U.S. delivery points. In common with every other producer in North America, the cost or benefit of fulfilling these contracts is included in the reported price received by the Company, to report on an effective wellhead price. The market value of the transportation is currently lower than the contracted price. The value of these contracts were included in the Gilbert Laustsen Jung 1999 year end reserves report.

Transportation Summaries

Period	Details	Volume
Present to October 2003	Transport on ANG and PGT to Malin (California)	3.3 mmcf/d
Present to October 2003	Transport on Foothills and Northern Border to Ventura (Illinois)	3.3 mmcf/d
Present to October 2003	Transport on Foothills and Northern Border to Harper (Illinois)	3.3 mmcf/d
Present to October 2008	Transport on ANG and PGT to Malin (California) The transport has a 25 percent discount	5 mmcf/d
Present to October 2008	Transport on TransCanada and Great Lakes to St. Clair (Michigan)	5 mmcf/d
November 2001 to October 2008	Transport on TransCanada and Great Lakes to St. Clair (Michigan)	5 mmcf/d
Present to October 2007	Transport on TransCanada to Niagara (New York)	5 mmcf/d
Present to October 2013	Transport on Foothills and Northern Border to Chicago	5 mmcf/d
November 2000 to October 2015	Transport on Alliance to Chicago. Amoco is managing for 5 years	18.7 mmcf/d

unaudited consolidated statements of income (loss)

Three months ended March 31

(in thousands)	2000	1999
REVENUE		
Oil and gas	**$ 37,283**	$ 25,652
Royalties	**(8,689)**	(4,353)
	28,594	21,299
Other	**119**	51
	28,713	21,350
EXPENSES		
Oil and gas	**6,714**	5,825
General and administrative	**1,617**	1,750
Interest	**3,373**	2,808
Capital and resource taxes	**656**	384
Site restoration	**641**	300
Depletion and depreciation	**12,102**	11,208
	25,103	22,275
Income (loss) before undernoted items	**3,610**	(925)
Future income taxes	**1,523**	450
Income (loss) from continuing operations	**2,087**	(1,375)
Loss from discontinued operations *(note 1)*	**(10,444)**	(40)
Net loss	**$ (8,357)**	$ (1,415)

Earnings per share *(note 3)*

See accompanying notes to consolidated financial statements.

(in thousands)	**March 31 2000**	December 31 1999
ASSETS		
Current assets:		
Cash	**$ 48**	$ 3
Accounts receivable	**26,878**	26,496
Inventory	**1,544**	1,073
Prepaid expenses	**2,777**	1,734
Current assets of discontinued operations	**3,619**	1,846
	34,866	31,152
Property and equipment	**458,297**	437,214
Non-current assets of discontinued operations	**21,298**	15,638
	$ 514,461	$ 484,004
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 65,626**	$ 41,985
Royalties and taxes payable	**7,878**	8,381
Current portion of long-term debt	**1,747**	–
Current liabilities of discontinued operations	**16,613**	7,477
	91,864	57,843
Long-term debt *(note 4)*	**205,000**	202,288
Site restoration provision	**6,132**	5,588
Future income taxes	**52,644**	51,510
Non-current liabilities of discontinued operations	**453**	456
Shareholders' equity:		
Capital stock	**118,719**	118,702
Term equity *(note 2)*	**41,564**	40,681
Retained earnings (deficit)	**(1,915)**	6,936
	158,368	166,319
	$ 514,461	$ 484,004

Subsequent events *(note 2)*

See accompanying notes to consolidated financial statements.

unaudited consolidated statements of cash flows

Three months ended March 31

(in thousands)		**2000**		1999
CASH PROVIDED BY (USED IN)				
OPERATIONS *(note 5)*				
Continuing operations	**$**	**19,199**	$	6,678
Discontinued operations		**(1,944)**		(54)
		17,255		6,624
FINANCING				
Issue of common shares		**17**		306
Bank borrowings		**4,459**		21,462
		4,476		21,768
INVESTING				
Continuing operations				
Property acquisitions		**(503)**		(6,649)
Property and equipment additions		**(44,721)**		(32,290)
Property dispositions		**12,039**		–
Change in non-cash working capital		**18,497**		8,078
		(14,688)		(30,861)
Discontinued operations				
Capital assets		**(12,361)**		2,469
Change in non-cash working capital		**5,363**		–
		(6,998)		2,469
		(21,686)		(28,392)
Increase in cash		**45**		–
Cash, beginning of period		**3**		–
Cash, end of period	**$**	**48**	$	–

Cash flow per share *(note 3)*

See accompanying notes to consolidated financial statements.

(in thousands)

1. DISCONTINUED OPERATIONS

To date, Genoil Inc. and its subsidiary, CE3 Technologies Inc., have not secured the necessary third party financing to fund capital expenditures and operating losses. As part of the process to consider strategic alternatives to maximize shareholder value, the Company has affirmed its decision not to provide financing to Genoil and CE3 beyond existing commitments.

The Company has announced the adoption of a formal plan to dispose of its investment in Genoil by way of distribution of the shares of Genoil to Beau Canada's shareholders.

The technology services (through Genoil's 100% subsidiary, CE3) have been reflected as discontinued operations. The Company has determined that a writedown is required as a full recovery of the net investment in the technology services is not likely as Genoil recapitalizes.

Effective January 1, 2000 the Company has reflected the technology services operations as discontinued operations.

	2000	1999
Technology services revenue	**$ –**	$ –
Technology services expenses	**1,744**	–
Administration	**200**	54
Depreciation and amortization	**500**	–
Provision for losses to date of disposition	**2,000**	–
Writedown of assets	**6,000**	–
	10,444	54
Loss before minority interest	**(10,444)**	(54)
Minority interest in losses	**–**	14
Loss from discontinued operations	**$ (10,444)**	$ (40)

2. PROFORMA FINANCIAL INFORMATION

The term equity instrument is due June 11, 2000. The term equity is payable at the option of the Company, in whole or in part, by the issue of common shares based on the market price of the shares. The option to pay in common shares expires on June 11, 2000. In May 2000 the holder of the term equity instrument agreed to extend the maturity date to December 12, 2000. The Company agreed to pay the principal and interest (aggregating $45,634) on December 12, 2000 in cash. The Company has a right to repay the subordinated debenture, including accrued interest, prior to maturity. The obligation is subordinated to borrowings under the bank operating and revolving credit facilities.

On May 12, 2000 the Company sold properties for $23 million. The proceeds were used to pay accounts payable and accrued liabilities.

After giving effect to the distribution of Genoil, the refinancing of the term equity and the sale of the properties, summarized proforma financial statement information is as follows:

Proforma Unaudited Consolidated Balance Sheets

	March 31, 2000
Current assets	**$ 31,247**
Property and equipment	**435,297**
	$ 466,544
Current liabilities before subordinated debenture	**$ 52,251**
Subordinated debenture	**41,564**
	93,815
Long-term debt	**205,000**
Site restoration	**6,132**
Future income taxes	**52,644**
Shareholders' equity	**108,953**
	$ 466,544

Proforma Unaudited Consolidated Statements of Income

Three months ended March 31		**2000**		1999
Revenue	**$**	**28,713**	$	21,350
Expenses before interest on subordinated debenture		**25,103**		22,275
Interest on subordinated debenture		**883**		863
		25,986		23,138
Income (loss) before income taxes		**2,727**		(1,788)
Future income taxes (reduction)		**1,029**		(979)
Net income (loss)	**$**	**1,698**	$	(809)

3. EARNINGS AND CASH FLOW PER SHARE

At March 31, 2000 the number of issued and outstanding common shares was 91,953,264 (March 31, 1999 – 91,568,023). The weighted average number of shares outstanding for the three months ended March 31, 2000 was 91,951,247 (1999 – 91,537,594).

The Company has granted options to officers, directors and employees to purchase 8,606,697 common shares exercisable from time to time prior to 2005. The average exercise price of these options is $2.11. The term equity holder has the right to purchase 7,900,000 common shares at $2.80 per share. The right expires June 10, 2000.

Three months ended March 31		**2000**		1999
Earnings (loss) per share from continuing operations				
Basic	**$**	**0.02**	$	(0.01)
Earnings (loss) per share				
Basic	**$**	**(0.10)**	$	(0.02)
Proforma basic		**0.02**		(0.01)
Cash flow per share from continuing operations				
Basic	**$**	**0.18**	$	0.12
Proforma basic		**0.17**		0.11
Fully diluted		**0.17**		0.11
Proforma fully diluted		**0.16**		0.12
Cash flow per share				
Basic	**$**	**0.16**	$	0.12
Proforma basic		**0.15**		0.11
Fully diluted		**0.15**		0.11
Proforma fully diluted		**0.16**		0.12

4. LONG-TERM DEBT

Beau Canada has a $205 million syndicated revolving credit facility and a $15 million operating credit facility. The operating credit facility is a demand facility. The revolving credit facility is structured as a one-year committed facility. Borrowings under the facility are limited to a borrowing base determined by the lenders. The lenders are currently conducting their annual review, including the determination of the borrowing base. Principal payments are required if the borrowing base is exceeded. If the facility is not extended, then the existing borrowing base is reduced by 10 equal semi-annual reductions. Principal repayments may also be required if significant property dispositions occur.

5. CASH PROVIDED BY (USED IN) OPERATIONS

Three months ended March 31	**2000**	1999
Income (loss) from continuing operations	**$ 2,087**	$ (1,375)
Items not involving cash:		
Depletion and depreciation	**12,102**	11,208
Site restoration	**641**	300
Future income taxes	**1,523**	450
Cash flow from continuing operations	**16,353**	10,583
Site restoration (paid) recovered	**98**	(351)
Change in non-cash working capital	**2,748**	(3,554)
Continuing operations	**19,199**	6,678
Loss from discontinued operations	**(10,444)**	(40)
Items not involving cash:		
Provision for losses to date of disposal	**2,000**	–
Writedown of assets	**6,000**	–
Depreciation and amortization	**500**	–
Minority interest in losses	**–**	(14)
Discontinued operations	**(1,944)**	(54)
	17,255	6,624

management's report

The financial statements of Beau Canada Exploration Ltd. were prepared by management in accordance with accounting principles generally accepted in Canada. The financial and operating information presented in this annual report is consistent with the financials statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of the financial information necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee of the Board of Directors has reviewed the financial statements, including the notes thereto, with management and the auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Michael J. Lang
Vice Chairman & Chief Financial Officer
March 31, 2000

William T. Cromb
Corporate Controller

auditors' report to the shareholders

We have audited the consolidated balance sheets of Beau Canada Exploration Ltd. as at December 31, 1999 and 1998 and the consolidated statements of income (loss), retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP
Chartered Accountants

Calgary, Canada
March 31, 2000
(except as to note 13 which is as of May 10, 2000)

consolidated balance sheets

As at December 31

(in thousands)	1999	1998
ASSETS		
Current assets:		
Cash	**$ 25**	$ 3,952
Accounts receivable	**27,434**	15,884
Inventory	**1,183**	1,672
Prepaid expenses	**2,510**	913
	31,152	22,421
Property and equipment *(note 3)*	**446,725**	410,930
Other assets *(note 4)*	**6,127**	–
	$ 484,004	$ 433,351
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 46,664**	$ 33,213
Royalties and taxes payable	**8,409**	3,069
Notes payable, unsecured	**1,144**	–
Current portion of long-term debt *(note 5)*	**1,626**	–
	57,843	36,282
Long-term debt *(note 5)*	**202,744**	162,521
Site restoration provision	**5,588**	4,777
Future income taxes	**51,510**	17,952
Minority interest	–	5,346
Shareholders' equity:		
Capital stock and term equity *(note 6)*	**159,383**	155,159
Retained earnings	**6,936**	51,314
	166,319	206,473
Subsequent events *(note 13)*		
	$ 484,004	$ 433,351

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Director

Director

consolidated statements of income (loss)

Years ended December 31

(in thousands)		1999		1998
REVENUE				
Oil and gas	$	**126,804**	$	108,870
Royalties		**(23,590)**		(16,963)
		103,214		91,907
Technology services		**583**		–
Other *(note 7)*		**567**		16,809
		104,364		108,716
EXPENSES				
Oil and gas		**25,481**		26,444
Technology services		**2,189**		–
General and administrative		**6,367**		6,150
Interest		**13,244**		13,887
Capital and resource taxes		**1,572**		1,381
Site restoration		**1,970**		1,302
Depletion and depreciation		**47,456**		42,560
Write-down of Cuban costs		**19,129**		–
		117,408		91,724
Income (loss) before income taxes and minority interest		**(13,044)**		16,992
Future income taxes (reduction) *(note 8)*		**(2,476)**		1,943
Income (loss) before minority interest		**(10,568)**		15,049
Minority interest		**5,768**		(2,575)
Net income (loss)	$	**(4,800)**	$	12,474
EARNINGS (LOSS) PER SHARE				
Basic	$	**(0.07)**	$	0.13
Fully diluted		**(0.07)**		0.12
Fully diluted, supplemental		**(0.03)**		0.12

See accompanying notes to consolidated financial statements.

consolidated statements of retained earnings

Years ended December 31

(in thousands)	**1999**	1998
Balance, beginning of year	**$ 51,314**	$ 39,951
Net income (loss)	**(4,800)**	12,474
Term equity charges, net of income tax benefit of $1,566 (1998 – $860) *(note 6)*	**(1,978)**	(1,111)
Reduction due to change in policy on accounting for income taxes *(note 8)*	**(37,600)**	–
Balance, end of year	**$ 6,936**	$ 51,314

See accompanying notes to consolidated financial statements.

consolidated statements of cash flows

Years ended December 31

(in thousands)	**1999**	1998
CASH PROVIDED BY (USED IN)		
OPERATIONS		
Net income (loss)	**$ (4,800)**	$ 12,474
Items not involving cash:		
Write-down of Cuban costs	**19,129**	–
Depletion and depreciation	**47,456**	42,560
Site restoration	**1,970**	1,302
Future income taxes (reduction)	**(2,476)**	1,943
Gain on sale of Cuban interests	–	(6,115)
Gain on sale of portfolio investment	–	(9,288)
Minority interest	**(5,768)**	2,575
Cash flow from operations	**55,511**	45,451
Site restoration paid	**(1,159)**	(537)
Change in non-cash working capital items	**(3,199)**	(8,507)
	51,153	36,407
FINANCING		
Issue of common shares and term equity	**680**	37,323
Share issue by a subsidiary	**422**	–
Long-term debt borrowings	**43,670**	88,434
Long-term debt repayment	**(4,535)**	(46,400)
Bridge loan facility borrowing	–	19,903
Bridge loan facility repayment	–	(27,636)
Note payable	–	(19,903)
	40,237	51,721
INVESTING		
Acquisitions *(note 2)*	**(2,246)**	(104,004)
Property and equipment additions:		
Producing properties	**(11,189)**	(3,749)
Exploration, development, equipment and facilities	**(84,450)**	(93,516)
Property dispositions	**3,900**	66,448
Technology services plants	**(6,055)**	–
Other	**(1,608)**	–
Sale of portfolio investment	–	39,806
Change in non-cash working capital items	**6,331**	10,839
	(95,317)	(84,176)
Increase (decrease) in cash	**(3,927)**	3,952
Cash, beginning of year	**3,952**	–
Cash, end of year	**$ 25**	$ 3,952
Cash flow per share:		
Basic	**$ 0.61**	$ 0.50
Fully diluted	**0.54**	0.46
Fully diluted, supplemental	**0.44**	0.42

See accompanying notes to consolidated financial statements.

1. SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The consolidated financial statements include the accounts of Beau Canada Exploration Ltd. and its subsidiaries. The statements have been prepared in accordance with Canadian generally accepted accounting principles.

Since a determination of some assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment.

Oil and gas operations

The Company follows the full cost method of accounting for oil and gas operations. All costs of exploring for and developing oil and gas reserves are capitalized and accumulated in cost centres established on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

The costs related to each cost centre, together with the cost of production equipment, are depleted and depreciated using the unit-of-production method based on the estimated gross proved reserves. Gas reserves and production are converted to equivalent barrels of crude oil based on relative energy content.

The costs of acquiring and evaluating significant unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

The costs (including exploratory dry holes) in cost centres from which there has been no commercial production are not subject to depletion until commercial production commences. The capitalized costs are periodically assessed to determine whether it is likely such costs will be recovered in the future. To the extent there are costs which are unlikely to be recovered in the future, they are written-off.

The capitalized costs less accumulated depletion and depreciation in each cost centre in which there is production are limited to an amount equal to the estimated future net revenue from proved reserves (based on prices and costs at the balance sheet date) plus the cost (net of impairments) of unproved properties. The total capitalized costs less accumulated depletion and depreciation, site restoration provision and future income taxes of all cost centres is further limited to an amount equal to the future net revenue from proved reserves plus the cost (net of impairments) of unproved properties of all cost centres less estimated future site restoration costs, general and administrative expenses, financing costs and income taxes.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

Certain of the exploration and development activities related to oil and gas operations are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities.

Site restoration costs

Estimated site restoration costs for oil and gas operations are provided for using the unit-of-production method based on the estimated gross proved reserves. Costs are estimated by Company engineers using current regulations, costs, technology and industry standards. Site restoration expenditures are charged to the accumulated provision account as incurred.

Future removal and site restoration costs for the sand washing plant and heavy oil field upgrader will be provided when they are probable and can be reasonably estimated.

Translation of foreign currency

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at rates of exchange in effect at the date of the consolidated balance sheet. Non-monetary items are translated at the rate of exchange in effect when the assets were acquired or obligations incurred. Gains or losses are included in income of the year except for gains or losses arising from the settlement of foreign currency denominated items associated with exploration activities which are capitalized. Other assets and liabilities and items affecting income are converted at rates of exchange in effect at the date of the transaction.

Hedging activities

The Company uses forward contracts to manage its exposure to commodity price, foreign exchange and interest rate fluctuations. Gains and losses on oil and gas and foreign exchange transactions are reported as adjustments to oil and gas revenues when the related production is sold and gains or losses on interest rate hedging transactions are reported as adjustments to interest on long-term debt.

Plant, upgrader and equipment

Plants are recorded at cost. Renewals and betterments are capitalized. Repairs and maintenance costs, other than major turnaround costs, are charged to operations as incurred. Depreciation is provided using the following methods and annual rates:

Sand washing plant	20% straight-line
Heavy oil field upgrader	10% straight-line
Equipment and furniture	20% straight-line

Cash

Cash is comprised of cash and term deposits with maturities of less than 90 days.

Income taxes

The Company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or subsequently enacted tax rates expected to apply when the asset is realized or the liability settled. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

Inventory

Material and equipment inventories are stated at the lower of cost, on a first-in, first-out basis, and net realizable value.

Patents, technology rights and goodwill

Patents and goodwill are recorded at cost and are amortized over five years on a straight-line basis. Technology rights are recorded at cost and will be amortized on a straight-line basis over the estimated useful life.

The Company periodically reviews the valuation and amortization of the patents and technology rights, taking into consideration any events and circumstances which might have impaired the fair value. The Company assesses impairment by determining whether the unamortized balance can be recovered from estimates of undiscounted future cash flows related to patent and technology use.

The Company periodically evaluates the carrying value of goodwill to determine if there has been a decline in value based on estimates of expected undiscounted cash flows from the sand washing operations.

2. ACQUISITIONS

Effective June 28, 1999, a subsidiary, Genoil Inc. ("Genoil"), acquired all of the outstanding common shares of CE3 Technologies Inc. ("CE3"), a private company marketing technologies developed to reduce heavy oil production costs including sand washing and heavy oil field processing and upgrading. This transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned values, and the cash consideration paid:	
Sand washing plant	$ 4,648
Patent rights	49
	4,697
Working capital deficiency	(4,613)
Long-term debt	(1,486)
	(1,402)
Goodwill	3,648
Cash paid	$ 2,246

The shareholders of CE3 are entitled to additional consideration, to a maximum of $8,000 per annum, should CE3 reach certain cash flow targets in 2000, 2001 and 2002.

Effective October 26, 1999, CE3 acquired all of the issued and outstanding shares of Enviremedial Services Inc. ("ESI"), a U.S. private company with oil-water separation technologies. This transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned values, and the non-cash consideration paid:	
Technology rights	$ 1,252
Working capital deficiency	(24)
Note payable (U.S. $850)	$ 1,228

The former shareholder of ESI is entitled to additional consideration should ESI achieve certain earnings targets in 2000, 2001 and 2002.

Effective March 6, 1998 the Company acquired, through a private placement, 56% of the issued and outstanding shares of Genoil, a public company with offshore and onshore pre-production oil and gas interests in Cuba. This transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned values, and the cash consideration paid:	
Oil and gas properties	$ 6,530
Working capital	69
Minority interest	(3,230)
Cash paid	$ 3,369

In September 1998, the Company acquired an additional 8% of the outstanding shares of Genoil as partial consideration on the sale to Genoil of royalty interests and producing properties in the Western Canadian Sedimentary Basin. The additional interest was acquired for $459 less than the reported minority interest value at the time. This difference was allocated to the carrying value of oil and gas properties.

In March 2000, the Company acquired, through a private placement, an additional 10% of the outstanding common shares of Genoil.

Effective April 1, 1998 the Company acquired the issued and outstanding shares of a private company primarily engaged in the exploration for and production of petroleum and natural gas in western Canada. In conjunction with this transaction, the Company acquired interests from partners of the private company. This transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned values, and the cash consideration paid:	
Oil and gas properties	$ 100,132
Working capital	503
Cash paid	$ 100,635

3. PROPERTY AND EQUIPMENT

1999	**Cost**	**Accumulated amortization**	**Net book value**
Oil and gas properties:			
Canada	**$ 633,014**	**$ 198,964**	**$ 434,050**
Sand washing plant	**9,421**	**1,444**	**7,977**
Heavy oil field upgrader	**1,350**	**–**	**1,350**
Furniture and equipment	**4,948**	**1,600**	**3,348**
	$ 648,733	**$ 202,008**	**$ 446,725**

1998	Cost	Accumulated amortization	Net book value
Oil and gas properties:			
Canada	$ 549,341	$ 154,715	$ 394,626
Cuba	13,621	100	13,521
Furniture and equipment	3,783	1,000	2,783
	$ 566,745	$ 155,815	$ 410,930

An expansion designed to double the capacity of the sand washing plant was started in 1999 and is expected to be completed prior to June 2000. The heavy oil field upgrader is currently being tested. CE3 is committed to expenditures relating to the expansion and start-up of the sand washing plant and the heavy oil field upgrader. These anticipated expenditures exceed the Company's $8 million limitation on advances to subsidiaries (see note 5). As a result, the recovery of the sand washing plant, the heavy oil field upgrader and other assets will depend on the ability of Genoil and CE3 to obtain necessary financing and ultimately attain profitable sand washing and field upgrader operations.

Genoil has completed the Cuban exploration program. As the program did not discover reserves, the carrying value of the Cuban properties was assessed not to be recoverable and a write-down of $19,129 was recorded during the year ended December 31, 1999.

As at December 31,1999 Canadian oil and gas interests included $44,000 (1998 – $39,000) relating to undrilled lands which have been excluded from depletion and depreciation calculations. Future development costs of proved undeveloped reserves of $57,000 (1998 – $36,000) are included in the depletion and depreciation calculation.

During the year ended December 31,1999 the Company capitalized overhead charges directly related to acquisition, exploration and development activities of $2,294 (1998 – $1,970).

Future site restoration liabilities to be expensed over the life of the remaining proved reserves are estimated to be $25,000 as at December 31, 1999. The Company has recorded $5,588 as a site restoration liability at December 31, 1999. To date, the Company has spent $3,058 on site restoration.

4. OTHER ASSETS

	Cost	Accumulated amortization	Net book value
Patents	$ 656	$ 114	$ 542
Technology rights	1,252	–	1,252
Goodwill	3,649	316	3,333
Power facility right	1,000	–	1,000
	$ 6,557	$ 430	$ 6,127

In December 1999 CE3 entered into an agreement with a public income fund to contract operate a power facility at Westlock, Alberta. Under the agreement, CE3 will pay $1.0 million to the public income fund and is committed to $1.0 million of capital expenditures on the facility by May 31, 2000. In addition, Genoil granted the public income fund 600,000 warrants; each warrant is convertible into one common share of Genoil at an exercise price of $0.40 per share prior to January 1, 2002. CE3 has the right to cancel the arrangement before December 31, 2000 at no additional cost. The agreement covers five, five-year terms with CE3 having the renewal option. CE3 will pay an annual fee to the public income fund of $1.8 million in 2000, $2.0 million in 2001, $2.2 million in 2002 and $2.4 million in 2003; $2.4 million plus inflation per annum thereafter. The public income fund has a right to cancel the arrangement on December 31, 2001 if CE3 has not paid the fund $4.2 million by that date.

As part of this transaction, CE3 reached an arrangement with the existing operator of the facility, a private company. Under this arrangement, CE3 will be the operator of the facility and will receive 85% of the cash flow until all of CE3 costs have been recovered. After recovery, CE3 will receive 66.7% of the cash flow.

This is a related party transaction as an officer and director of the Company is indebted to the public income fund and this same individual controls the private company that was the operator of the facility. In addition, a director of the public income fund is a director of the Company.

The power facility was constructed in 1999. The recovery of the investment will depend upon improved plant performance.

5. LONG-TERM DEBT

	1999	1998
Revolving production bank loan	**$ 202,288**	$ 162,521
Bank term loan	**1,188**	–
Note payable, unsecured (U.S. $600)	**894**	–
	204,370	162,521
Less current portion of long-term debt	**(1,626)**	–
	$ 202,744	$ 162,521

Beau Canada has a $205 million (1998 – $205 million) syndicated revolving credit facility and a $15 million (1998 – $15 million) operating credit facility. The operating credit facility is a demand facility with several interest and borrowing options. The revolving credit facility is structured as a one year committed facility. Borrowings under the facility are limited to a borrowing base determined by the lenders. Principal payments are required only if the borrowing base is exceeded. If the facility is not extended, the then existing borrowing base is reduced by 10 equal semi-annual reductions. Principal repayments may also be required if significant property dispositions occur. The Company may borrow in Canadian or U.S. dollars under several interest rate options. The margin on the interest rate can vary depending on debt to cash flow ratios. The average interest rate on the facility during 1999 was 6.6% (1998 – 6.4%).

The revolving production bank loan is secured by a $300 million debenture with a first floating charge over Beau Canada's assets and property. This credit facility contains certain financial covenants, including limitations on advances to subsidiaries and the payment of dividends.

CE3 has a $1,188 bank term facility in place at December 31, 1999. The loan is repayable in equal monthly instalments to February 2003, bears interest at bank prime plus 1.75% and is secured by a general security agreement. The loan has been included in the current portion of long-term debt.

Estimated principal repayments over the next six years if the revolving production bank loan is not extended are as follows:

2000	$ 1,626
2001	38,727
2002	41,011
2003	41,006
2004	41,000
2005	41,000

Interest includes $13,113 (1998 – $11,506) of interest on long-term debt and $131 (1998 – $2,381) of other interest.

6. CAPITAL STOCK AND TERM EQUITY

	Number of Common shares	Stated Capital
Balance December 31, 1997	90,049,446	$ 115,065
Flow-through share issue[1]	719,976	1,202
Exercise of stock options	741,300	1,367
Term equity	–	36,600
Accrued term equity charges	–	1,971
Issue costs, net of income tax benefit of $800	–	(1,046)
Balance December 31, 1998	91,510,722	155,159
Exercise of stock options	432,191	687
Accrued term equity charges	–	3,544
Issue costs	–	(7)
Balance December 31, 1999	**91,942,913**	**$ 159,383**

[1] *includes 567,234 common shares issued to officers and directors for cash proceeds of $947.*

The term equity represents an aggregate principal amount of $36,600, due June 11, 2000, which yields an annual return of 7.5%. The term equity principal and interest are payable on June 11, 2000 at the option of the Company, in whole or in part, by the issue of common shares based on the then market price of the shares. The Company has the right to satisfy its obligation by paying the principal and interest at any time. The obligation is subordinated to borrowings under the Company's operating and revolving credit facilities.

The Company granted warrants to the term equity holder to purchase 7,900,000 common shares at $2.80 per share. The warrants expire June 10, 2000. If exercised, the proceeds will be used to pay a portion of the term equity.

The Company has granted options to officers, directors and employees to purchase 8,595,912 common shares. The average exercise price of these options at December 31, 1999 is $2.13 per share (1998 – $2.11 per share). The options are exercisable from time to time prior to December 2005 as follows:

	Number of options
2000	2,656,023
2001	921,431
2002	2,588,450
2003	1,602,008
2004	612,350
2005	215,650
	8,595,912

Changes in the number of options outstanding during each of the two years ended December 31,1999 and 1998 are as follows:

	1999	1998
Balance, beginning of year	**8,673,298**	7,597,192
Granted	**846,300**	2,654,862
Exercised	**(432,191)**	(741,300)
Expired	**(491,495)**	(837,456)
Balance, end of year	**8,595,912**	8,673,298

The Company has a shareholders rights plan. The plan requires confirmation by the shareholders in 2002. If a bid to acquire control of the Company is made, the plan is designed to give the board of directors time to consider alternatives to allow shareholders to receive full and fair value for their shares. In the event that a bid, other than a permitted bid, is made, shareholders become entitled to exercise rights to acquire common shares at 25% of market value. This would significantly dilute the value of the bidder's holdings.

7. OTHER REVENUE

	1999	1998
Gain on sale of portfolio investment	**$ –**	$ 9,288
Gain on sale of Cuban offshore interests	**–**	6,115
Other	**567**	1,406
	$ 567	$ 16,809

The Company had a 2.2% interest in the Alliance Pipeline and Aux Sable projects. In November 1997 the Company sold the interests to Fort Chicago and purchased 5,307,452 units of Fort Chicago for $30.5 million. In February 1998 the Company sold the units of Fort Chicago for proceeds of $39,800 and repaid a bridge loan facility. The Company realized a gain of $9,288 on the sale.

The Company sold its Cuban offshore interests in 1998 for total cash and non-cash proceeds of $10,100. At the time of the sale, the Company had $3,985 invested in these properties. As a result, a pre-tax gain of $6,115 was recognized on the sale.

8. INCOME TAXES

In 1999 the Company changed its method of accounting for income taxes. Effective January 1, 1999 the liability method was adopted; prior thereto, the Company followed the deferral method. The new method was applied retroactively without restatement of prior period financial statements. At January 1, 1999 the future income tax liability was increased by $37,600 and retained earnings was decreased by $37,600. These adjustments were a result of the recognition of future taxes where the tax basis of acquired companies was less than the acquisition cost. The effect of the change in accounting was to reduce the loss by $1,800 ($0.02 per share) for the year ended December 31, 1999.

The income tax provision differs from the amount which would result from applying the expected combined federal and provincial income tax rate of 44% to net income (loss). The differences between the expected income tax provision and the reported income tax provision are summarized as follows:

	1999	1998
Expected income tax provision	**$ (5,739)**	$ 7,477
Increase (decrease) resulting from:		
Non-deductible crown royalties and mineral taxes	**7,673**	4,653
Resource allowance	**(7,934)**	(7,650)
Non-deductible depletion	**–**	3,574
Non-taxable portion of gain on sale	**–**	(1,022)
Benefit on prior years' losses	**–**	(2,620)
Benefit on capital losses	**–**	(3,066)
Capital and resource taxes	**692**	597
Benefit on subsidiaries' current year's losses not recognized	**2,832**	–
Reported income tax provision	**$ (2,476)**	$ 1,943

The provision for future income taxes arises from temporary differences in the recognition of revenues and expenses for income tax and accounting purposes. The temporary differences comprising the future income tax asset (liability) at December 31, 1999 are as follows:

Oil and gas properties	$ (54,700)
Production equipment, plants and other	2,285
Non-capital losses	9,000
Capital losses	3,600
	(39,815)
Valuation allowance, attributable to capital losses and certain non-capital losses	(11,695)
	$ (51,510)

At December 31, 1999 the Company and its subsidiaries have approximately $310,000 of deductions for Canadian tax purposes, including operating losses available to reduce future income for tax purposes. Canadian oil and gas property expenses of $17,000 are deductible at 10% per year, with the balance of the future deductions being pools deductible at rates ranging from 25-100% per year. Approximately $60,000 of these future deductions are the subject of a review by taxation authorities. At December 31, 1999 the future income tax liability includes a benefit of approximately $19,000 on these deductions. The Company is of the opinion that this deduction will be available and the benefit recognized will be realized.

9. COMMITMENT

CE3 has committed to capital expenditures relating to the expansion of the sand washing plant, the heavy oil field upgrader and the power facility. At December 31, 1999 the remaining expenditures are estimated to be $10,000. These expenditures will be incurred prior to June 2000. The expenditures will be partially funded by advances from the Company; CE3 and Genoil are seeking financing for the remainder.

10. RELATED PARTY TRANSACTIONS

Reference is made to note 4.

During the years ended December 31, 1999 and 1998 the Company utilized financial instruments to manage exposure to fluctuations in commodity prices. The counter-party to certain of these financial instruments is the holder of the term equity. The transactions were measured at the exchange amount which approximates fair value.

During the year ended December 31, 1999 the Company advanced $1,000 to a public company where an officer and director is an officer and director of the Company. Subsequent to December 31, 1999 the borrower sought protection under the Companies Creditor Arrangement Act and is now seeking creditor approval of a proposed restructuring plan. The officer and director has provided a guarantee to reimburse the Company on or before June 30, 2001 for losses on the advances.

During 1999 the Company acquired an equity interest in a private company controlled by an officer and director for $300 and committed to provide up to $300 of interest-bearing advances to fund testing of heavy oil processing technologies. The Company has a right to put its equity and advances to the officer and director for $700.

The Company has advanced amounts to a director and officer of the Company. The amount owed was $1,288 at December 31, 1999 (December 31, 1998 – $952) and is included in accounts receivable. The maximum amount owed to the Company during 1999 was $1,288 (1998 – $1,186). The loan bears interest at bank prime plus 1% and is unsecured.

11. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company is exposed to fluctuations in commodity prices, interest rates, and exchange rates. The Company monitors and, when appropriate, utilizes financial instruments to manage its exposure to these risks.

Financial instruments are subject to fluctuations in prices and rates but, by nature of being hedges of an actual or anticipated transaction, any gains or losses are offset by gains or losses on the hedged transaction.

The Company is exposed to losses in the event of non-performance by counter-parties to the financial instruments. The Company deals with major institutions and does not anticipate non-performance by counterparties.

Commodity price risk management

The Company enters into oil and gas sales agreements to provide exposure to a portfolio of pricing indices. At December 31, 1999 the Company has sales agreements to sell 114 mbls of oil (1250 bls per day) at WTI less U.S. $4.75/bbl through March 2000. In addition, the Company has entered into agreements to sell 18 bcf of gas (10 mmcf per day) at $2.78 through October 2004 and 27 bcf of gas (25 mmcf per day) at AECO less U.S. $0.195 for the period from April 2001 through March 2004.

In addition to the sales agreements, the Company enters into oil and gas price swaps to hedge against reductions in commodity prices. At year-end, the Company had the following financial instruments:

December 31, 1999	Period	Daily volume	Contract volume		Average price
Gas price swaps	**Through October 2000**	**30 mmcf**	**9.2 bcf**	**$**	**2.63**
	November 2000 – October 2001	**20 mmcf**	**7.3 bcf**	**$**	**2.65**
Gas price ceiling	**Through October 2000**	**5 mmcf**	**1.5 bcf**	**US$**	**2.41**
Oil price collars	**Calendar 2000**	**2,000 bbls**	**732 mbbls**	**Floor US$**	**18.50**
		2,000 bbls	**732 mbbls**	**Ceiling US$**	**20.85**
December 31, 1998					
Gas price swaps	Through March 1999	35 mmcf	3.2 bcf	$	2.89
	April – October 1999	40 mmcf	8.6 bcf	$	2.47
	April 1999 – October 2004	10 mmcf	18.3 bcf	US$	1.86
	November 1999 – October 2000	30 mmcf	11.0 bcf	$	2.60
	November 1999 – October 2001	20 mmcf	7.3 bcf	$	2.64
Gas price ceiling	Through October 2000	20 mmcf	13.4 bcf	US$	2.41

As at December 31, 1999 a payment of $10,300 (1998 – $4,100) would have been required to terminate these financial instruments.

Interest risk management

Through interest rate swap contracts the interest rate, excluding bank margins, on borrowings is fixed as follows:

Rate	Term	Amount
December 31, 1999		
5.190%	**November 1996 to November 2000**	**$ 25,000**
6.040%	**August 1998 to July 2001**[1]	**30,000**
5.658%	**August 1998 to July 2002**	**25,000**
5.693%	**August 1998 to July 2003**	**30,000**
		$ 110,000
December 31, 1998		
5.190%	November 1996 to November 2000	$ 25,000
5.445%	August 1998 to July 1999	30,000
6.040%	August 1998 to July 2001[1]	30,000
5.658%	August 1998 to July 2002	25,000
5.693%	August 1998 to July 2003	30,000
		$ 140,000

[1] *agreement may be extended, at the bank's option, for two years at the same rate*

At December 31, 1999, $400 would have been received if these contracts were terminated (1998 – $3,000 payment by the Company).

Foreign currency risk management

The Company is exposed to foreign currency fluctuations. The Company uses financial instruments, including forward exchange contracts and currency options, to manage this exposure. At December 31, 1999 and 1998 there were no contracts or options outstanding.

Credit risk management

Accounts receivable include amounts receivable for oil and gas sales. These sales are generally made to large, credit worthy purchasers. The Company views the credit risks on these items as low. Amounts receivable from joint venture partners included in accounts receivable are recoverable from production and, accordingly, the Company views credit risks on these amounts as minimal.

Fair values of financial instruments

Accounts receivable, accounts payable and accrued liabilities have carrying values that approximate fair value due to the near maturity of these financial instruments.

Long-term debt and the term equity have a carrying value that approximates fair value.

12. SEGMENTED INFORMATION

In 1999 and 1998 the Company had oil and gas operations in Canada and Cuba. Following the acquisition of CE3, the Company provides heavy oil processing technology services in Canada.

	Oil and gas		Technology	
1999	Canada	Cuba	Services	Total
Revenue	**$ 103,781**	**$ –**	**$ 583**	**$ 104,364**
Operating profit (loss)	**70,861**	**(165)**	**(1,941)**	**68,755**
Interest	**12,638**	**207**	**399**	**13,244**
Site restoration	**1,970**	**–**	**–**	**1,970**
Depletion, amortization and write-down	**46,461**	**19,129**	**995**	**66,585**
Future income taxes (reduction)	**(2,476)**	**–**	**–**	**(2,476)**
Minority interest (reduction)	**–**	**(5,768)**	**–**	**(5,768)**
Net income (loss)	**4,966**	**(6,431)**	**(3,335)**	**(4,800)**
Cash flow from operations	**58,223**	**(372)**	**(2,340)**	**55,511**
Capital expenditures	**86,131**	**5,608**	**9,909**[1]	**101,648**
Total assets	**466,683**	**316**	**17,005**	**484,004**

[1] *includes $2,246 on the acquisition of CE3*

	Oil and gas		Technology	
1998	Canada	Cuba	Services	Total
Revenue	$ 102,601	$ 6,115		$ 108,716
Operating profit (loss)	68,964	5,777		74,741
Interest	13,887	–		13,887
Site restoration	1,302	–		1,302
Depletion and amortization	42,560	–		42,560
Income taxes	1,849	94		1,943
Minority interest	–	2,575		2,575
Net income (loss)	9,366	3,108		12,474
Cash flow from operations	39,674	5,777		45,451
Capital expenditures	124,361	10,460[1]		134,821
Total assets	412,046	21,305		433,351

[1] *includes $3,369 on the acquisition of Genoil*

13. SUBSEQUENT EVENTS

On April 27, 2000 the Company announced that it had commenced a process to consider strategic alternatives to maximize shareholder value.

CE3 has continued to incur operating losses and has a significant working capital deficiency. To May 10, 2000 Genoil and CE3 have not secured third party financing necessary to fund the losses and capital expenditures. The Company has advanced most of the funds permitted under a limitation on advances to subsidiaries in the credit facility agreement. A failure of CE3 and Genoil to obtain the necessary financing could require that stated amounts of technology service assets and liabilities be reflected on a liquidation basis which would differ from the going concern basis.

statistical summary

(as of December 31)	**1999**	1998	1997	1996	1995	1994	1993	1992	1991	1990
FINANCIAL *($thousands)*										
Oil & gas production revenue	**126,804**	108,870	110,850	95,933	74,266	59,755	24,277	10,288	9,277	10,548
Net income	**(4,800)**	12,474	12,753	10,023	6,515	7,009	2,009	277	257	902
Per share (basic)	**(0.07)**	0.13	0.15	0.12	0.09	0.10	0.05	0.02	0.02	0.06
Cash flow	**55,511**	45,451	56,169	42,604	31,606	28,512	9,546	3,053	2,330	2,727
Per share (basic)	**0.61**	0.50	0.64	0.50	0.42	0.41	0.22	0.17	0.15	0.18
Production										
Gas (mmcf/d)	**89.1**	91.1	70.7	60.9	54.5	44.2	18.1	5.3	3.5	2.6
Oil & NGLs *(bbls/d)*	**7,038**	8,303	10,454	8,304	6,311	4,724	2,167	1,258	1,272	1,250
Prices										
Gas *($/mcf)*	**2.34**	1.89	1.76	1.56	1.51	1.89	1.81	1.44	1.36	1.86
Oil & Liquids *($/bbl)*	**19.76**	15.20	17.13	20.14	19.21	16.95	15.53	16.17	16.25	19.98
Proven reserves										
Gas *(bcf)*	**286**	298	261	212	207	216	196	15	16	16
Oil & NGLs *(mmbbls)*	**25.2**	22.0	24.2	21.5	16.3	10.5	10.0	3.5	3.7	3.3
Proven & probable reserves										
Gas *(bcf)*	**407**	412	311	239	234	244	222	15	17	16
Oil & NGLs *(mmbbls)*	**33.7**	29.3	27.5	23.5	19.7	13	12.1	3.5	4.1	3.3
Net acres	**748,000**	688,000	734,000	635,000	616,000	549,000	367,000	35,600	31,200	32,300
Net undeveloped acres	**552,000**	495,000	501,000	366,000	307,000	223,000	82,000	9,000	15,000	–
BALANCE SHEET *($thousands)*										
Current assets	**31,152**	22,421	48,633	26,445	11,623	10,550	8,209	10,506	2,381	2,808
Property and equipment	**452,852**	410,930	310,355	240,788	206,693	178,363	121,631	20,692	17,359	16,164
Total assets	**484,004**	433,351	358,988	267,233	218,316	188,913	129,840	31,198	19,920	18,972
Current liabilities	**57,843**	36,282	61,804	35,947	20,261	22,679	8,367	5,922	4,448	2,489
Long term debt	**202,744**	162,521	120,487	79,622	75,131	52,949	39,586	10,142	11,513	13,148
Deferred liabilities and credits	**5,588**	4,777	4,012	4,625	6,694	12,874	1,469	385	657	385
Deferred income tax	**51,510**	17,952	17,669	10,969	5,684	4,350	–	–	–	–
Minority interest	–	5,346	–	–	–	–	–	–	–	–
Shareholders' equity	**166,319**	206,473	155,016	136,070	110,546	96,061	80,418	14,749	3,302	2,950
Total liabilities and equity	**484,004**	433,351	358,988	267,233	218,316	188,913	129,840	31,198	19,920	18,972
CAPITAL EXPENDITURES *($thousands)*										
Property and equipment	**91,680**	93,519	115,427	78,813	52,311	65,070	21,029	5,592	2,476	225
Property acquisitions	**13,868**	107,178	1,392	5,319	21,259	8,509	86,028	–	609	15,972
Property dispositions	**(3,900)**	(68,448)	(11,752)	(23,749)	(22,552)	–	–	–	–	–
Net capital expenditures	**101,648**	134,249	105,067	60,383	51,018	73,579	107,057	5,592	3,085	16,197
NETBACKS (per boe) (10:1)										
Revenue	**$21.78**	$17.13	$17.33	$18.21	$17.30	$17.90	$16.71	$15.71	$15.68	$19.18
Royalties	**(4.05)**	(2.67)	(2.44)	(2.93)	(1.96)	(1.98)	(2.73)	(2.58)	(2.42)	(3.98)
Operating expenditures	**(4.38)**	(4.16)	(4.12)	(5.15)	(5.27)	(5.02)	(5.00)	(5.35)	(5.52)	(6.01)
Netback	**13.35**	10.30	10.77	10.13	10.07	10.90	8.98	7.78	7.74	9.19
General & administrative	**(1.09)**	(0.97)	(0.80)	(0.77)	(1.09)	(0.99)	(1.16)	(1.51)	(1.54)	(1.21)
Interest and other	**(2.45)**	(1.96)	(0.96)	(1.00)	(1.36)	(1.07)	(1.08)	(1.27)	(2.18)	(3.02)
Taxes	**(0.27)**	(0.22)	(0.23)	(0.28)	(0.26)	(0.30)	(0.17)	(0.31)	(0.08)	–
Cash flow	**9.54**	7.15	8.78	8.08	7.36	8.54	6.57	4.69	3.94	4.96
Depletion & depreciation	**(11.44)**	(6.70)	(5.55)	(4.99)	(5.31)	(4.81)	(4.59)	(3.73)	(2.89)	(3.32)
Site restoration	**(0.34)**	(0.20)	(0.19)	(0.19)	(0.22)	(0.33)	(0.51)	(0.19)	(0.21)	–
Future income taxes	**0.43**	(0.31)	(1.05)	(1.00)	(0.31)	(1.30)	–	–	–	–
Interest adjustment and non-cash gains	–	2.42	–	–	–	–	(0.09)	(0.34)	(0.40)	–
Minority interest in Genoil	**0.99**	(0.41)	–	–	–	–	–	–	–	–
Future net income	**$ (0.82)**	$ 1.95	$ 1.99	$ 1.90	$ 1.52	$ 2.10	$ 1.38	$ 0.43	$ 0.44	$ 1.64
Year end share price	**$ 1.70**	$ 1.93	$ 2.90	$ 2.40	$ 1.63	$ 2.00	$ 2.35	$ 1.15	$ 0.70	$ 0.50
Average daily volume *(thousands)*	**157.7**	148.4	158.1	173.4	105.9	83.7	83.7	35.6	15.1	8.8

DIRECTORS

Bruce R. Libin, Q.C.
Chairman, Beau Canada Exploration Ltd.
President, B.R. Libin Capital Corp.

Ed Chwyl
Chairman and Chief Executive Officer,
Ventus Energy Ltd.

Michael J. Lang
Vice Chairman & Chief Financial Officer

Harley Mintz
Managing Partner, Mintz & Partners, LLP

Jeffrey T. Smith
Director

OFFICERS & SENIOR MANAGEMENT

Bruce R. Libin
Chairman

Michael J. Lang
Vice Chairman & Chief Financial Officer

Robert N. Waldner
Senior Vice President & Chief Operating Officer

William T. Cromb
Corporate Controller

Kenneth B. Cruikshank
Vice President, Land

Brent J. Harris
Vice President, Exploration

Ronald E. Vogel
Vice President, Marketing

William J. Wowchuk
Vice President, Operations

Donald M. Boykiw
Secretary

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Investors are encouraged to contact our Transfer Agent and Registrar, CIBC Mellon Trust Company, for information regarding their security holdings. They can be reached at:

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STOCK EXCHANGE LISTINGS

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Consolidated Financial Statements of

BEAU CANADA EXPLORATION LTD.

Years ended December 31, 1999 and 1998

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Beau Canada Exploration Ltd. as at December 31, 1999 and 1998 and the consolidated statements of income (loss), retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 31, 2000
(except as to note 13 which is as of May 10, 2000)

BEAU CANADA EXPLORATION LTD.

Consolidated Balance Sheets

December 31, 1999 and 1998
(in thousands)

	1999	1998
Assets		
Current assets:		
Cash	$ 25	$ 3,952
Accounts receivable	27,434	15,884
Inventory	1,183	1,672
Prepaid expenses	2,510	913
	31,152	22,421
Property and equipment (note 3)	446,725	410,930
Other assets (note 4)	6,127	–
	$ 484,004	$ 433,351
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 46,664	$ 33,213
Royalties and taxes payable	8,409	3,069
Notes payable, unsecured	1,144	–
Current portion of long-term debt (note 5)	1,626	–
	57,843	36,282
Long-term debt (note 5)	202,744	162,521
Site restoration provision	5,588	4,777
Future income taxes	51,510	17,952
Minority interest	–	5,346
Shareholders' equity:		
Capital stock and term equity (note 6)	159,383	155,159
Retained earnings	6,936	51,314
	166,319	206,473
Subsequent events (note 13)		
	$ 484,004	$ 433,351

See accompanying notes to consolidated financial statements.

On behalf of the Board:

"Thomas Bugg" Director

"Harley Mintz" Director

BEAU CANADA EXPLORATION LTD.

Consolidated Statements of Income (Loss)

Years ended December 31, 1999 and 1998
(in thousands)

	1999	1998
Revenue:		
Oil and gas	$ 126,804	$ 108,870
Royalties	(23,590)	(16,963)
	103,214	91,907
Technology services	583	–
Other (note 7)	567	16,809
	104,364	108,716
Expenses:		
Oil and gas	25,481	26,444
Technology services	2,189	–
General and administrative	6,367	6,150
Interest	13,244	13,887
Capital and resource taxes	1,572	1,381
Site restoration	1,970	1,302
Depletion and depreciation	47,456	42,560
Write-down of Cuban costs	19,129	–
	117,408	91,724
Income (loss) before income taxes and minority interest	(13,044)	16,992
Future income taxes (reduction) (note 8)	(2,476)	1,943
Income (loss) before minority interest	(10,568)	15,049
Minority interest	5,768	(2,575)
Net income (loss)	$ (4,800)	$ 12,474
Earnings (loss) per share:		
Basic	$ (0.07)	$ 0.13
Fully diluted	(0.07)	0.12
Fully diluted, supplemental	(0.03)	0.12

Consolidated Statements of Retained Earnings

Years ended December 31, 1999 and 1998
(in thousands)

	1999	1998
Balance, beginning of year	$ 51,314	$ 39,951
Net income (loss)	(4,800)	12,474
Term equity charges, net of income tax benefit of $1,566 (1998 - $860) (note 6)	(1,978)	(1,111)
Reduction due to change in policy on accounting for income taxes (note 8)	(37,600)	–
Balance, end of year	$ 6,936	$ 51,314

See accompanying notes to consolidated financial statements.

BEAU CANADA EXPLORATION LTD.

Consolidated Statements of Cash Flows

Years ended December 31, 1999 and 1998
(in thousands)

	1999	1998
Cash provided by (used in):		
Operations:		
Net income (loss)	$ (4,800)	$ 12,474
Items not involving cash:		
Write-down of Cuban costs	19,129	–
Depletion and depreciation	47,456	42,560
Site restoration	1,970	1,302
Future income taxes (reduction)	(2,476)	1,943
Gain on sale of Cuban interests	–	(6,115)
Gain on sale of portfolio investment	–	(9,288)
Minority interest	(5,768)	2,575
Cash flow from operations	55,511	45,451
Site restoration paid	(1,159)	(537)
Change in non-cash working capital items	(3,199)	(8,507)
	51,153	36,407
Financing:		
Issue of common shares and term equity	680	37,323
Share issue by a subsidiary	422	–
Long-term debt borrowings	43,670	88,434
Long-term debt repayment	(4,535)	(46,400)
Bridge loan facility borrowing	–	19,903
Bridge loan facility repayment	–	(27,636)
Note payable	–	(19,903)
	40,237	51,721
Investing:		
Acquisitions (note 2)	(2,246)	(104,004)
Property and equipment additions:		
Producing properties	(11,189)	(3,749)
Exploration, development, equipment and facilities	(84,450)	(93,516)
Property dispositions	3,900	66,448
Technology services plants	(6,055)	–
Other	(1,608)	–
Sale of portfolio investment	–	39,806
Change in non-cash working capital items	6,331	10,839
	(95,317)	(84,176)
Increase (decrease) in cash	(3,927)	3,952
Cash, beginning of year	3,952	–
Cash, end of year	$ 25	$ 3,952
Cash flow per share:		
Basic	$ 0.61	$ 0.50
Fully diluted	0.54	0.46
Fully diluted, supplemental	0.44	0.42

See accompanying notes to consolidated financial statements.

1. **Significant accounting policies:**

Basis of presentation:

The consolidated financial statements include the accounts of Beau Canada Exploration Ltd. and its subsidiaries. The statements have been prepared in accordance with Canadian generally accepted accounting principles.

Since a determination of some assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment.

Oil and gas operations:

The Company follows the full cost method of accounting for oil and gas operations. All costs of exploring for and developing oil and gas reserves are capitalized and accumulated in cost centres established on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

The costs related to each cost centre, together with the cost of production equipment, are depleted and depreciated using the unit-of-production method based on the estimated gross proved reserves. Gas reserves and production are converted to equivalent barrels of crude oil based on relative energy content.

The costs of acquiring and evaluating significant unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

The costs (including exploratory dry holes) in cost centres from which there has been no commercial production are not subject to depletion until commercial production commences. The capitalized costs are periodically assessed to determine whether it is likely such costs will be recovered in the future. To the extent there are costs which are unlikely to be recovered in the future, they are written-off.

The capitalized costs less accumulated depletion and depreciation in each cost centre in which there is production are limited to an amount equal to the estimated future net revenue from proved reserves (based on prices and costs at the balance sheet date) plus the cost (net of impairments) of unproved properties. The total capitalized costs less accumulated depletion and depreciation, site restoration provision and future income taxes of all cost centres is further limited to an amount equal to the future net revenue from proved reserves plus the cost (net of impairments) of unproved properties of all cost centres less estimated future site restoration costs, general and administrative expenses, financing costs and income taxes.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

Certain of the exploration and development activities related to oil and gas operations are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities.

Site restoration costs:

Estimated site restoration costs for oil and gas operations are provided for using the unit-of-production method based on the estimated gross proved reserves. Costs are estimated by Company engineers using current regulations, costs, technology and industry standards. Site restoration expenditures are charged to the accumulated provision account as incurred.

Future removal and site restoration costs for the sand washing plant and heavy oil field upgrader will be provided when they are probable and can be reasonably estimated.

Translation of foreign currency:

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at rates of exchange in effect at the date of the consolidated balance sheet. Non-monetary items are translated at the rate of exchange in effect when the assets were acquired or obligations incurred. Gains or losses are included in income of the year except for gains or losses arising from the settlement of foreign currency denominated items associated with exploration activities which are capitalized. Other assets and liabilities and items affecting income are converted at rates of exchange in effect at the date of the transaction.

Hedging activities:

The Company uses forward contracts to manage its exposure to commodity price, foreign exchange and interest rate fluctuations. Gains and losses on oil and gas and foreign exchange transactions are reported as adjustments to oil and gas revenues when the related production is sold and gains or losses on interest rate hedging transactions are reported as adjustments to interest on long-term debt.

Plant, upgrader and equipment:

Plants are recorded at cost. Renewals and betterments are capitalized. Repairs and maintenance costs, other than major turnaround costs, are charged to operations as incurred. Depreciation is provided using the following methods and annual rates:

Sand washing plant	20% straight-line
Heavy oil field upgrader	10% straight-line
Equipment and furniture	20% straight-line

Cash:

Cash is comprised of cash and term deposits with maturities of less than 90 days.

Income taxes:

The Company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or subsequently enacted tax rates expected to apply when the asset is realized or the liability settled. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

Inventory:

Material and equipment inventories are stated at the lower of cost, on a first-in, first-out basis, and net realizable value.

Patents, technology rights and goodwill:

Patents and goodwill are recorded at cost and are amortized over five years on a straight-line basis. Technology rights are recorded at cost and will be amortized on a straight-line basis over the estimated useful life.

The Company periodically reviews the valuation and amortization of the patents and technology rights, taking into consideration any events and circumstances which might have impaired the fair value. The Company assesses impairment by determining whether the unamortized balance can be recovered from estimates of undiscounted future cash flows related to patent and technology use.

The Company periodically evaluates the carrying value of goodwill to determine if there has been a decline in value based on estimates of expected undiscounted cash flows from the sand washing operations.

(in thousands)

2. Acquisitions:

Effective June 28, 1999, a subsidiary, Genoil Inc. ("Genoil"), acquired all of the outstanding common shares of CE3 Technologies Inc. ("CE3"), a private company marketing technologies developed to reduce heavy oil production costs including, sand washing and heavy oil field processing and upgrading. The transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned values, and the cash consideration paid:

Sand washing plant	$	4,648
Patent rights		49
		4,697
Working capital deficiency		(4,613)
Long-term debt		(1,486)
		(1,402)
Goodwill		3,648
Cash paid	$	2,246

The shareholders of CE3 are entitled to additional consideration, to a maximum of $8,000 per annum, should CE3 reach certain income targets in 2000, 2001 and 2002.

Effective October 26, 1999, CE3 acquired all of the issued and outstanding shares of Enviremedial Services Inc. ("ESI"), a U.S. private company with oil-water separation technologies. This transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned values, and the non-cash consideration paid:

Technology rights	$	1,252
Working capital deficiency		(24)
Note payable (U.S. $850)	$	1,228

Years ended December 31, 1999 and 1998
(in thousands)

The former shareholder of ESI is entitled to additional consideration should ESI achieve certain earnings targets in 2000, 2001 and 2002.

Effective March 6, 1998 the Company acquired, through a private placement, 56% of the issued and outstanding shares of Genoil, a public company with offshore and onshore pre-production oil and gas interests in Cuba. This transaction has been accounted for by the purchase method with the result of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned value, and the cash consideration paid:

Oil and gas properties	$	6,530
Working capital		69
Minority interest		(3,230)
Cash paid	$	3,369

In September 1998 the Company acquired an additional 8% of the outstanding shares of Genoil as partial consideration on the sale to Genoil of royalty interests and producing properties in the Western Canadian Sedimentary Basin. The additional interest was acquired for $459 less than the reported minority interest value at the time. This difference was allocated to the carrying value of oil and gas properties.

In March 2000, the Company acquired, through a private placement, an additional 10% of the outstanding common shares of Genoil.

Effective April 1, 1998 the Company acquired the issued and outstanding shares of a private company primarily engaged in the exploration for and production of petroleum and natural gas in western Canada. In conjunction with this transaction, the Company acquired interests from partners of the private company. This transaction has been accounted for by the purchase method with the results of operations included in the financial statements from the date of acquisition. The purchase price has been allocated as follows:

Net assets acquired, at assigned values, and the cash consideration paid:

Oil and gas properties	$	100,132
Working capital		503
Cash paid	$	100,635

Years ended December 31, 1999 and 1998
(in thousands)

3. Property and equipment:

1999		Cost		Accumulated amortization		Net book value
Oil and gas properties:						
Canada	$	633,014	$	198,964	$	434,050
Sand washing plant		9,421		1,444		7,977
Heavy oil field upgrader		1,350		–		1,350
Furniture and equipment		4,948		1,600		3,348
	$	648,733	$	202,008	$	446,725

1998		Cost		Accumulated amortization		Net book value
Oil and gas properties:						
Canada	$	549,341	$	154,715	$	394,626
Cuba		13,621		100		13,521
Furniture and equipment		3,783		1,000		2,783
	$	566,745	$	155,815	$	410,930

An expansion designed to double the capacity of the sand washing plant was started in 1999 and is expected to be completed prior to June 2000. The heavy oil field upgrader is currently being tested. CE3 is committed to expenditures relating to the expansion and start-up of the sand washing plant and the heavy oil upgrader. These anticipated expenditures exceed the Company's $8 million limitation on advances to subsidiaries (see note 5). As a result, the recovery of the sand washing plant, the heavy oil field upgrader and other assets will depend on the ability of Genoil and CE3 to obtain necessary financing and ultimately attain profitable sand washing and field upgrader operations.

Genoil has completed the Cuban exploration program. As the program did not discover reserves, the carrying value of the Cuban properties was assessed not to be recoverable and a write-down of $19,129 was recorded during the year ended December 31, 1999.

As at December 31,1999 Canadian oil and gas interests included $44,000 (1998 - $39,000) relating to undrilled lands which have been excluded from depletion and depreciation calculations. Future development costs of proven undeveloped reserves of $57,000 (1998 - $36,000) are included in the depletion and depreciation calculation.

(in thousands)

During the year ended December 31,1999 the Company capitalized overhead charges directly related to acquisition, exploration and development activities of $2,294 (1998 - $1,970).

Future site restoration liabilities to be expensed over the life of the remaining proved reserves are estimated to be $25,000 as at December 31, 1999. The Company has recorded $5,588 as a site restoration liability at December 31, 1999. To date, the Company has spent $3,058 on site restoration.

4. Other assets:

	Cost	Accumulated depreciation	Net book value
Patents	$ 656	$ 114	$ 542
Technology rights	1,252	–	1,252
Goodwill	3,649	316	3,333
Power facility right	1,000	–	1,000
	$ 6,557	$ 430	$ 6,127

In December 1999 CE3 entered into an agreement with a public income fund to contract operate a power facility at Westlock, Alberta. Under the agreement, CE3 will pay $1.0 million to the public income fund and is committed to $1.0 million of capital expenditures on the facility by May 31, 2000. In addition, Genoil granted the public income fund 600,000 warrants; each warrant is convertible into one common share of Genoil at an exercise price of $0.40 per share prior to January 1, 2002. CE3 has the right to cancel the arrangement before December 31, 2000 at no additional cost. The agreement covers five, five-year terms with CE3 having the renewal option. CE3 will pay an annual fee to the public income fund of $1.8 million in 2000, $2.0 million in 2001, $2.2 million in 2002 and $2.4 million in 2003; $2.4 million plus inflation per annum thereafter. The public income fund has a right to cancel the arrangement on December 31, 2001 if CE3 has not paid the fund $4.2 million by that date.

As part of this transaction, CE3 reached an arrangement with the existing operator of the facility, a private company. Under this arrangement, CE3 will be the operator of the facility and will receive 85% of the cash flow until all of CE3 costs have been recovered. After recovery, CE3 will receive 66.7% of the cash flow.

This is a related party transaction as an officer and director of the Company is indebted to the public income fund and this same individual controls the private company that was the operator of the facility. In addition, a director of the public income fund is a director of the Company.

(in thousands)

The power facility was constructed in 1999. The recovery of the investment will depend upon improved plant performance.

5. Long-term debt:

	1999	1998
Revolving production bank loan	$ 202,288	$ 162,521
Bank term loan	1,188	–
Note payable, unsecured (U.S. $600)	894	–
	204,370	162,521
Less current portion of long-term debt	(1,626)	–
	$ 202,744	$ 162,521

Beau Canada has a $205 million (1998 - $205 million) syndicated revolving credit facility and a $15 million (1998 - $15 million) operating credit facility. The operating credit facility is a demand facility with several interest and borrowing options. The revolving credit facility is structured as a one year committed facility. Borrowings under the facility are limited to a borrowing base determined by the lenders. Principal payments are required only if the borrowing base is exceeded. If the facility is not extended, the then existing borrowing base is reduced by 10 equal semi-annual reductions. Principal repayments may also be required if significant property dispositions occur. The Company may borrow in Canadian or U.S. dollars under several interest rate options. The margin on the interest rate can vary depending on debt to cash flow ratios. The average interest rate on the facility during 1999 was 7.6% (1998 - 6.4%).

The revolving production bank loan is secured by a $300 million debenture with a first floating charge over Beau Canada's assets and property. This credit facility contains certain financial covenants, including limitations on advances to subsidiaries and the payment of dividends.

CE3 has a $1,188 bank term facility in place at December 31, 1999. The loan is repayable in equal monthly instalments to February 2003, bears interest at bank prime plus 1.75% and is secured by a general security agreement. The loan has been included in the current portion of long-term debt.

(in thousands)

Estimated principal repayments over the next five years if the revolving production bank loan is not extended are as follows:

2000	$ 1,626
2001	38,727
2002	41,011
2003	41,006
2004	41,000
2005	41,000

Interest includes $13,113 (1998 - $11,506) of interest on long-term debt and $131 (1998 - $2,381) of other interest.

6. Capital stock and term equity:

	Number of common shares	Stated capital
Balance December 31, 1997	90,049,446	$ 115,065
Flow-through share issue [1]	719,976	1,202
Exercise of stock options	741,300	1,367
Term equity	–	36,600
Accrued term equity charges	–	1,971
Issue costs, net of income tax benefit of $800	–	(1,046)
Balance December 31, 1998	91,510,722	155,159
Exercise of stock options	432,191	687
Accrued term equity charges	–	3,544
Issue costs	–	(7)
Balance December 31, 1999	91,942,913	$ 159,383

[1] includes 567,234 common shares issued to officers and directors for cash proceeds of $947

The term equity represents an aggregate principal amount of $36,600 million, due June 11, 2000, which yields an annual return of 7.5%. The term equity principal and interest are payable on June 11, 2000 at the option of the Company, in whole or in part, by the issue of common shares based on the then market price of the shares. The Company has the right to satisfy its obligation by paying the principal and interest at any time. The obligation is subordinated to borrowings under the Company's operating and revolving credit facilities.

(in thousands)

The Company granted warrants to the term equity holder to purchase 7,900,000 common shares at $2.80 per share. The warrants expire June 10, 2000. If exercised, the proceeds will be used to pay a portion of the term equity.

The Company has granted options to officers, directors and employees to purchase 8,595,912 common shares. The average exercise price of these options at December 31, 1999 is $2.13 per share (1998 - $2.11 per share). The options are exercisable from time to time prior to December 2005 as follows:

	Number of options
2000	2,656,023
2001	921,431
2002	2,588,450
2003	1,602,008
2004	612,350
2005	215,650
	8,595,912

Changes in the number of options outstanding during each of the two years ended December 31,1999 and 1998 are as follows:

	1999	1998
Balance, beginning of year	8,673,298	7,597,192
Granted	846,300	2,654,862
Exercised	(432,191)	(741,300)
Expired	(491,495)	(837,456)
Balance, end of year	8,595,912	8,673,298

The Company has a shareholders rights plan. The plan requires confirmation by the shareholders in 2002. If a bid to acquire control of the Company is made, the plan is designed to give the board of directors time to consider alternatives to allow shareholders to receive full and fair value for their shares. In the event that a bid, other than a permitted bid, is made, shareholders become entitled to exercise rights to acquire common shares at 25% of market value. This would significantly dilute the value of the bidder's holdings.

Years ended December 31, 1999 and 1998
(in thousands)

7. Other revenue:

	1999	1998
Gain on sale of portfolio investment	$ –	$ 9,288
Gain on sale of Cuban offshore interests	–	6,115
Other	567	1,406
	$ 567	$ 16,809

The Company had a 2.2% interest in the Alliance Pipeline and Aux Sable projects. In November 1997 the Company sold the interests to Fort Chicago and purchased 5,307,452 units of Fort Chicago for $30.5 million. In February 1998 the Company sold the units of Fort Chicago for proceeds of $39,800 and repaid a bridge loan facility. The Company realized a gain of $9,288 on the sale.

The Company sold its Cuban offshore interests in 1998 for total cash and non-cash proceeds of $10,080. At the time of the sale, the Company had $3,965 invested in these properties. As a result, a pre-tax gain of $6,115 was recognized on the sale.

8. Income taxes:

In 1999 the Company changed its method of accounting for income taxes. Effective January 1, 1999 the liability method was adopted; prior thereto, the Company followed the deferral method. The new method was applied retroactively without restatement of prior period financial statements. At January 1, 1999 the future income tax liability was increased by $37,600 and retained earnings was decreased by $37,600. These adjustments were a result of the recognition of future taxes where the tax basis of acquired companies was less than the acquisition cost. The effect of the change in accounting was to reduce the loss by $1,800 ($0.02 per share) for the year ended December 31, 1999.

Years ended December 31, 1999 and 1998
(in thousands)

The income tax provision differs from the amount which would result from applying the expected combined federal and provincial income tax rate of 44% to net income (loss). The differences between the expected income tax provision and the reported income tax provision are summarized as follows:

	1999	1998
Expected income tax provision	$ (5,739)	$ 7,477
Increase (decrease) resulting from:		
Non-deductible crown royalties and mineral taxes	7,673	4,653
Resource allowance	(7,934)	(7,650)
Non-deductible depletion	–	3,574
Non-taxable portion of gain on sale	–	(1,022)
Benefit on prior years' losses	–	(2,620)
Benefit on capital losses	–	(3,066)
Capital and resource taxes	692	597
Benefit on subsidiaries' current year's losses not recognized	2,832	–
Reported income tax provision	$ (2,476)	$ 1,943

The provision for future income taxes arises from temporary differences in the recognition of revenues and expenses for income tax and accounting purposes. The temporary differences comprising the future income tax asset (liability) at December 31, 1999 are as follows:

Oil and gas properties	$ (54,700)
Production equipment, plants and other	2,285
Non-capital losses	9,000
Capital losses	3,600
	(39,815)
Valuation allowance, attributable to capital losses and certain non-capital losses	(11,695)
	$ (51,510)

At December 31, 1999 the Company and its subsidiaries have approximately $310,000 of deductions for Canadian tax purposes, including operating losses available to reduce future income for tax purposes. Canadian oil and gas property expenses of $17,000 are deductible at 10% per year, with the balance of the future deductions being pools deductible at annual rates ranging from 25-100% per year. Approximately $60,000 of these future deductions are the subject of a review by taxation authorities. At December 31, 1999 the future income tax liability includes a benefit of approximately $19,000 on these deductions. The Company is of the opinion that this deduction will be available and the benefit recognized will be realized.

9. Commitment:

CE3 has committed to capital expenditures relating to the expansion of the sand washing plant, the heavy oil field upgrader and the power facility. At December 31, 1999 the remaining expenditures are estimated to be $10,000. These expenditures will be incurred prior to June 2000. The expenditures will be partially funded by advances from the Company; CE3 and Genoil are seeking financing for the remainder.

10. Related party transactions:

Reference is made to note 4.

During the year ended December 31, 1999 and 1998 the Company utilized financial instruments to manage exposure to fluctuations in commodity prices. The counter-party to certain of these financial instruments is the holder of the term equity. The transactions were measured at the exchange amount which approximates fair value.

During the year ended December 31, 1999 the Company advanced $1,000 to a public company where an officer and director is an officer and director of the Company. Subsequent to December 31, 1999 the borrower sought protection under the Companies Creditor Arrangement Act and is now seeking creditor approval of a proposed restructuring plan. The officer and director has provided a guarantee to reimburse the Company, on or before June 30, 2001, for losses on the advance.

During 1999 the Company acquired an equity interest in a private company controlled by an officer and director for $300 and committed to provide up to $300 of interest-bearing advances to fund testing of heavy oil processing technologies. The Company has a right to put its equity and advances to the officer and director for $700.

The Company has advanced amounts to a director and officer of the Company. The amount owed was $1,288 at December 31, 1999 (December 31, 1998 - $952) and is included in accounts receivable. The maximum amount owed to the Company during 1999 was $1,288 (1998 - $1,186). The loan bears interest at bank prime plus 1% and is unsecured.

(in thousands)

11. Risk management and financial instruments:

The Company is exposed to fluctuations in commodity prices, interest rates, and exchange rates. The Company monitors and, when appropriate, utilizes financial instruments to manage its exposure to these risks.

Financial instruments are subject to fluctuations in prices and rates but, by nature of being hedges of an actual or anticipated transaction, any gains or losses are offset by gains or losses on the hedged transaction.

The Company is exposed to losses in the event of non-performance by counter-parties to the financial instruments. The Company deals with major institutions and does not anticipate non-performance by counterparties.

Commodity price risk management:

The Company enters into oil and gas sales agreements to provide exposure to a portfolio of pricing indices. At December 31, 1999 the Company has sales agreements to sell 114 mbls of oil (1250 bls per day) at WTI less U.S. $4.75/bbl through March 2000. In addition, the Company has entered into agreements to sell 18 bcf of gas (10 mmcf per day) at $2.78 through October 2004 and 27 bcf of gas (25 mmcf per day) at AECO less U.S. $0.195 for the period from April 2001 through March 2004.

In addition to the sales agreements, the Company enters into oil and gas price swaps to hedge against reductions in commodity prices. At year-end, the Company had the following financial instruments:

December 31, 1999	Period	Daily volume	Contract volume	Average price per mcf
Gas price swaps	Through October 2000	30 mmcf	9.2 bcf	$ 2.63
	November 2000 - October 2001	20 mmcf	7.3 bcf	$ 2.65
Gas price ceiling	Through October 2000	5 mmcf	1.5 bcf	US$ 2.41
Oil price collars	Calendar 2000	2,000 bbls	732 mbbls	Floor US$18.50
		2,000 bbls	732 mbbls	Ceiling US$20.85

(in thousands)

December 31, 1998				
Gas price swaps	Through March 1999	35 mmcf	3.2 bcf	$ 2.89
	April - October 1999	40 mmcf	8.6 bcf	$ 2.47
	April 1999 - October 2004	10 mmcf	18.3 bcf	US$ 1.86
	November 1999 - October 2000	30 mmcf	11.0 bcf	$ 2.60
	November 1999 - October 2001	20 mmcf	7.3 bcf	$ 2.64
Gas pricing ceiling	Through October 2000	20 mmcf	13.4 bcf	US$ 2.41

As at December 31, 1999 a payment of $10,300 (1998 - $4,100) would have been required to terminate these financial instruments.

Interest risk management:

Through interest rate swap contracts the interest rate, excluding bank margins, on borrowings is fixed as follows:

Rate	Term	Amount
December 31, 1999:		
5.190%	November 1996 to November 2000	$ 25,000
6.040%	August 1998 to July 2001 (1)	30,000
5.658%	August 1998 to July 2002	25,000
5.693%	August 1998 to July 2003	30,000
		$ 110,000
December 31, 1998:		
5.190%	November 1996 to November 2000	$ 25,000
5.445%	August 1998 to July 1999	30,000
6.040%	August 1998 to July 2001	25,000
5.658%	August 1998 to July 2002	30,000
5.693%	August 1998 to July 2003	30,000
		$ 140,000

(1) agreement may be extended, at the bank's option, for two years at the same rate

At December 31, 1999, $400 would have been received if these contracts were terminated (1998 - $3,000 payment by the Company).

(in thousands)

Foreign currency risk management:

The Company is exposed to foreign currency fluctuations. The Company uses financial instruments, including forward exchange contracts and currency options, to manage this exposure. At December 31, 1999 and 1998 there were no contracts or options outstanding.

Credit risk management:

Accounts receivable include amounts receivable for oil and gas sales. These sales are generally made to large, credit worthy purchasers. The Company views the credit risks on these items as low. Amounts receivable from joint venture partners included in accounts receivable are recoverable from production and, accordingly, the Company views credit risks on these amounts as minimal.

Fair values of financial instruments:

Accounts receivable, accounts payable and accrued liabilities have carrying values that approximate fair value due to the near maturity of these financial instruments.

Long-term debt and the term equity have a carrying value that approximates fair value.

12. Segmented information:

In 1999 and 1998 the Company had oil and gas operations in Canada and Cuba. Following the acquisition of CE3, the Company provides heavy oil processing technology services in Canada.

	Oil and gas		Technology	
1999	Canada	Cuba	Services	Total
Revenue	$ 103,781	$ –	$ 583	$ 104,364
Operating profit (loss)	70,861	(165)	(1,941)	68,755
Interest	12,638	207	399	13,244
Site restoration	1,970	–	–	1,970
Depletion, amortization and write-down	46,461	19,129	995	66,585
Future income taxes (reduction)	(2,476)	–	–	(2,476)
Minority interest (reduction)	–	(5,768)	–	(5,768)
Net income (loss)	4,966	(6,431)	(3,335)	(4,800)
Cash flow from operations	58,223	(372)	(2,340)	55,511
Capital expenditures	86,131	5,608	9,909 (1)	101,648
Total assets	466,683	316	17,005	484,004

(1) includes $2,246 on the acquisition of CE3

Years ended December 31, 1999 and 1998
(in thousands)

	Oil and gas		Technology	
1999	Canada	Cuba	Services	Total
Revenue	$ 102,601	$ 6,115		$ 108,716
Operating profit (loss)	68,964	5,777		74,741
Interest	13,887	–		13,887
Site restoration	1,302	–		1,302
Depletion and amortization	42,560	–		42,560
Income taxes	1,849	94		1,943
Minority interest	–	2,575		2,575
Net income (loss)	9,366	3,108		12,474
Cash flow from operations	39,674	5,777		45,451
Capital expenditures	124,361	10,460 (1)		134,821
Total assets	412,046	21,305		433,351

(1) includes $3,369 on the acquisition of Genoil

13. Subsequent events

On April 27, 2000 the Company announced that it had commenced a process to consider strategic alternatives to maximize shareholder value.

CE3 has continued to incur operating losses and has a significant working capital deficiency. To May 10, 2000 Genoil and CE3 have not secured third party financing necessary to fund the losses and capital expenditures. The Company has advanced most of the funds permitted under a limitation on advances to subsidiaries in the credit facility agreement. A failure of CE3 and Genoil to obtain the necessary financing could require that stated amounts of technology service assets and liabilities be reflected on a liquidation basis which would differ from the going concern basis.

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