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TUSK ENERGY INC.

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2001 Annual Report >

STOCKHOLDER INFORMATION

As of December 31, 2001 the number of common shares outstanding was 15,953,774. The Annual Meeting of TUSK Energy Inc. will be held at 2:00 p.m. Calgary time on Thursday, May 23, 2002 at The 400 Club, 710 - 4th Avenue S.W., Calgary, Alberta.

TUSK
ENERGY INC.

CORPORATE PROFILE

TUSK Energy Inc. is a public company engaged in the exploration for, development of and production of oil and gas in Western Canada. The common shares of the Company trade on The Toronto Stock Exchange (Symbol: TKE). TUSK is a reporting issuer in the provinces of Ontario, Saskatchewan, Alberta and British Columbia.

The major assets of the Company are its interests at Saddle Lake, Whitefish Lake and Shane, Alberta (natural gas exploration/development and production), Hartaven, Saskatchewan (light oil development and production), Meekwap, Alberta (light oil and natural gas production and development) and Strachan, Alberta (natural gas exploration/development and production). The Company also has minor light oil production at Willesden Green, Alberta, minor gas production at a number of Alberta locations (Carvel, Deer, Hilda) and minor heavy oil production with development potential at two locations in Saskatchewan (Silverdale, Epping). The exploration programs of the Company concentrate on natural gas prospects. The Company is focused on operating as many of its investments as possible.

HIGHLIGHTS

	Quarter Ended December 31 2001	Year Ended December 31 2001	Year Ended December 31 2000	Percentage Change
Revenue (net of royalties)	$ 2,736,698	$ 8,651,117	$ 6,805,788	+27%
Net Income (Loss)	$ 114,088	$ 1,292,189	$ 908,592	+42%
Per Share	$ 0.01	$ 0.09	$ 0.06	+50%
Cash Flow				
From Operations	$ 1,503,838	$ 4,924,939	$ 3,544,892	+39%
Per Share	0.10	$ 0.34	$ 0.25	+36%
Working Capital (Deficiency)		$ (1,226,789)	$ (2,223,265)	-45%
Total Assets		$ 40,401,035	$ 33,062,958	+22%
Long Term Debt		$ 14,221,115	$ 4,350,000	+226%
Weighted Average Common Shares		14,595,675	14,225,941	+3%
Production				
Oil & NGL's (bpd)	576	389	475	-18%
Gas (Mcfd)	5,207	3,760	1,417	+165%
Boepd	1,444	1,031	711	+45%
Reserves (proven plus 50% probable)				
Oil & NGL's (Mbbls)		2,231	2,204	+1%
Gas (MMcf)		21,054	14,448	+46%
BOE		5,739	4,612	+24%
Land Holdings				
gross acres		185,341	193,093	-4%
net acres		67,172	71,742	-6%

ABBREVIATION TABLE

ARTC	Alberta Royalty Tax Credit
APO	after payout
BPO	before payout
BTAX	before income tax
bopd	barrels of oil per day
bpd	barrels per day
boe or BOE	barrels of oil equivalent
boepd	barrels of oil equivalent per day
DCF	discounted cash flow
Mbbls	thousands of barrels
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcfd	thousand cubic feet per day
NAV	net asset value
NGL	natural gas liquids
WI	working interest
WTI	West Texas Intermediate

Conversions

1 barrel of oil = 0.15891 cubic metres

1 Mcf of gas = 28.17399 cubic metres

1 barrel of oil equivalent (BOE) = 6 Mcf gas

MESSAGE TO SHAREHOLDERS

During 2001, TUSK's production and cash flow increased steadily in spite of commodity prices trending lower through most of the year. Production escalated to an exit rate in excess of 1,700 boepd from an average of 648 boepd in the first quarter.

The year was marked by numerous drilling successes in three principal areas: Saddle Lake and Shane, Alberta and Hartaven, Saskatchewan. These properties have become the three main producing assets of the Company representing 31%, 22% and 29% of production respectively at year end.

Momentum built during the 2001 fiscal year has continued into 2002. Production growth is expected to continue at a similar pace in 2002 as TUSK expands and exploits the prospects that were successful in 2001.

Achievements during 2001 include the following:

- participated in 30 wells (15 oil, 11 gas);
- drilling success rate of more than 92% on a net basis;
- acquired Spirit Energy – increasing to 50% the Company's interests in the Keyano Pimee Joint Venture (Saddle Lake and Whitefish Lake);
- consistent growth in cash flow and assets per share;
- consistent growth in production;
- reserve additions replaced production by 400%;
- developed new core producing area at Hartaven, Saskatchewan;
- gas discovery at Shane, Alberta;
- construction and tie-in of compressor facility at Saddle Lake, Alberta.

SUCCESS

[illegible]

[illegible]

The discovery well at Shane, Alberta (TUSK 17%) was drilled during the first quarter of 2001. Production commenced in mid-October after construction of facilities and pipelines. Current production is approximately 10 MMcfd with 35 barrels of NGL per MMcf (340 boepd net).

First Nations exploration and development opportunities arose from the acquisition of Auburn Energy Ltd. in 2000. In May 2001 TUSK acquired Spirit Energy Ltd., increasing its interests in more than 96 square miles of lands on the Saddle Lake and Whitefish Lake First Nations to 50%. During 2001, a total of 7 new gas wells were drilled at Saddle Lake and Whitefish Lake. Success rate was 100%.

Eleven successful oil wells (5.3 net), including two horizontal wells, have been developed since June at Hartaven, Saskatchewan. Production increased to a rate in excess of 500 bopd at year end. An additional horizontal well (TUSK 50%) was drilled in early March 2002.

The success of the Hartaven oil project has been balanced by the gas discoveries at Saddle Lake and Shane. As of the end of the fiscal year, oil and NGL's represented 44% of total production while natural gas represented 56%. Our strategy for growth will emphasize gas exploration and risk diversification. During 2002, TUSK will continue to work towards providing the best return for shareholders while keeping exploration, development and financial risk at acceptable levels.

To mitigate financial risk, a costless collar for natural gas, put in place in May of 2001, provides for a minimum field price of $5.00 per Mcf (maximum $10.68 per Mcf) for 2.1 MMcfd. This arrangement will continue until December 31, 2002. The Company has also taken steps to insure against the negative impact of any softening in oil price by arranging a costless collar for the 2002 fiscal year on 200 barrels of oil per day. This collar is based on the WTI price of oil with a low of US$17.00 and a high of US$23.75 per barrel of oil. On February 25, 2002 the Company put a costless collar on an additional 200 barrels of oil per day for the balance of 2002 with a low of US$17.00 and a high of US$25.10. On March 1, 2002 the Company fixed a floor price of US$17.00 on 200 barrels of oil per day for the period March 1, 2002 to December 31, 2002. A total of 600 bopd is subject to the US$17.00 floor price until the end of 2002.

Growth has been primarily through drilling. The Company has numerous low risk drilling opportunities at Saddle Lake, Whitefish Lake and Hartaven. These should provide predictable and positive drilling results leading to steady expansion of productive capability.

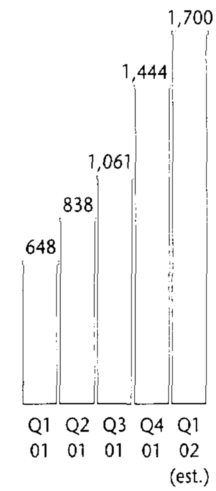
Commodity prices are significantly weaker than a year ago. This situation may provide favourable opportunities for TUSK due to downward pressure on property, land and services costs. Our expanding production and cash flow put the Company in a good position to make additional acquisitions during 2002.

The market for the shares of small public oil and gas companies in general and TUSK in particular remained fairly soft through 2001. Exploiting the opportunity to acquire our own shares at prices substantially below asset value, TUSK purchased 523,000 common shares pursuant to normal course issuer bids and 1,568,656 pursuant to exempt issuer bids during the year and returned them to treasury for cancellation. The average purchase price was $0.93 per common share during 2001. As of the end of the year there were 15,953,774 common shares issued and outstanding (17,953,744 fully-diluted).

Production grew rapidly throughout the year from 648 boepd (Q1) to 838 boepd (Q2) to 1,061 boepd (Q3) to reach 1,444 boepd (Q4). Production during the first quarter of 2002 is expected to average more than 1,700 boepd.

The rapid growth experienced by TUSK during the year led to capital expenditures of $12.2 million during fiscal 2001, approximately 2.5 times cash flow. In addition, $3.0 million was spent to acquire Spirit Energy. To provide additional capital, $3.4 million was raised in October 2001 through the issue of 3,400,000 flow-through common shares at an issue price of $1.00 each. The line of credit was expanded throughout the year in response to the drilling success of the Company. The line increased from $7.6 million at the start of the fiscal year to $15 million in September and increased again during the first quarter of 2002 to $18 million reflecting the growth in producing reserves as of December 31, 2001. Planned capital expenditures on currently identified projects of approximately $9 million during 2002 are not expected to require any additional borrowings or share issuances.

Average Daily Production
(boepd)



CONSISTENT GROWTH IN PRODUCTION

The outlook is very positive. TUSK has achieved consistent growth in the past 18 months. Numerous low risk drilling locations at both Saddle Lake and Hartaven, and the installation of a compressor and pipelines at Whitefish Lake will provide predictable and sustained growth in the future. Higher risk projects such as Shane have the potential to accelerate corporate growth substantially. During 2001, TUSK spent $2.8 million on 2-D seismic, 3-D seismic and land. This continual development of new plays through grassroots exploration will provide additional drilling opportunities for TUSK during 2002 and subsequent years.

The success of the past year would not have been possible without the commitment of our employees, the leadership of our management team and the guidance provided by our directors. The contributions of all are an integral part of the success of the Company.

[Signed]

Norman W. Holton
President and Chief Executive Officer
March 14, 2002

HIGHLIGHTS

- drilled discovery gas well at Shane, Alberta (17% W.I.);
- participated in 11 oil wells at Hartaven, Saskatchewan for 100% success;
- drilled 5 gas discoveries at Saddle Lake for 100% success;
- drilled 2 gas discoveries at Whitefish Lake for 100% success;
- started Shane production in October – now producing 340 boepd net to TUSK;
- increased Hartaven production to exit year at over 500 bopd;
- increased working interest at Saddle Lake/Whitefish Lake to 50% with acquisition of Spirit Energy;
- constructed compressor facility and gas pipelines at Saddle Lake;
- increased production 2.2 times from 648 boepd in first quarter 2001 to 1,444 boepd in fourth quarter 2001.

EXPLORATION & LAND

During the year TUSK participated in 30 wells, drilling 28 and re-entering 2, resulting in 15 gross oil (6.20 net), 11 gross gas (4.75 net) and 4 gross dry holes (0.96 net).

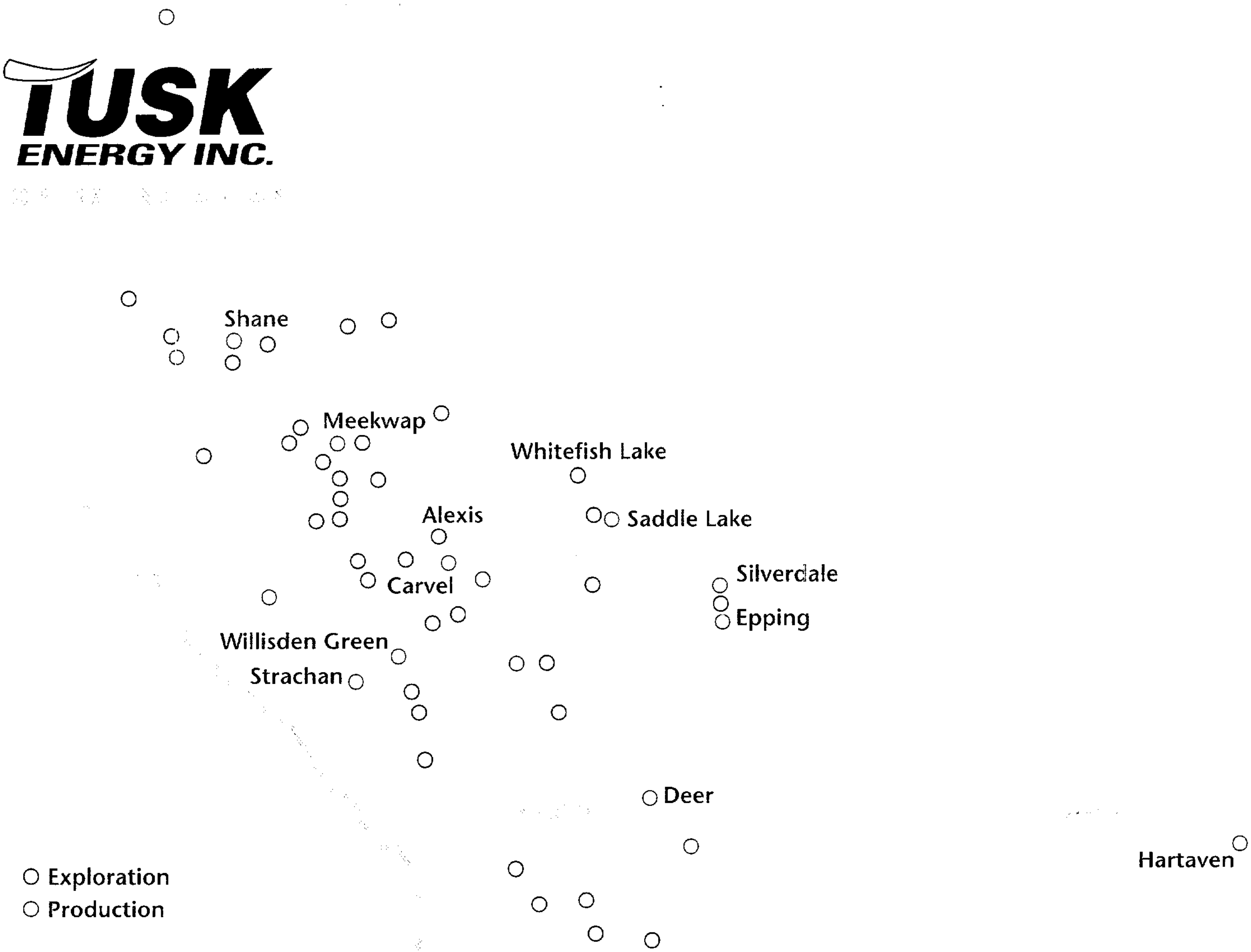
Three areas, Saddle Lake/Whitefish Lake, Alberta (7 gas wells), Hartaven, Saskatchewan (11 oil wells) and Shane, Alberta (1 gas well, 1 dry hole) accounted for 67% of the wells drilled by the Company.

GRASSROOTS EXPLORATION FOCUS ON GAS

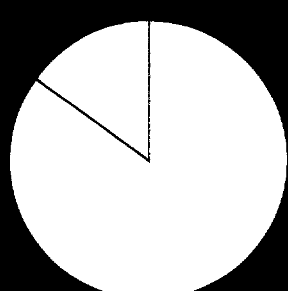
Our plan for the coming year is to exploit and expand upon the success of 2001. TUSK spent $2.0 million on land and $0.8 million on both 2-D and 3-D seismic during 2001 to expand opportunities on successful plays and to confirm new grassroots exploration plays which will provide additional drilling opportunities for TUSK in 2002 and subsequent years.

	Gross	Net
Oil	15	6.28
Natural Gas	11	4.75
Dry	4	0.96
	30	**11.98**
Success Rate	**87%**	**92%**

TUSK ENERGY INC.

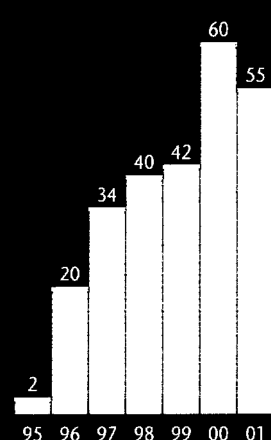


2001 Net Acreage



Developed – 15%
Undeveloped – 85%

Undeveloped Land
(000's net acres)



PROPERTY REVIEW

Saddle Lake

TUSK's Saddle Lake property is located approximately 130 kilometres (80 miles) northeast of Edmonton near St. Paul, Alberta. TUSK, through wholly-owned subsidiary Auburn Energy Ltd., is the operator of 16 producing gas wells, half of which are dual zone producers. Approximately 67% of the production is handled at a TUSK operated compressor station commissioned in 2001.

This property is part of a very successful joint venture arrangement with Keyano Pimee Exploration Company Ltd., a private company wholly-owned by the Saddle Lake and Whitefish Lake First Nations. In the second quarter of 2001, TUSK acquired a private company, Spirit Energy Ltd., which increased the Company's interest in the joint venture to 50%.

Sales gas volumes, net to TUSK, have grown from an average of 620 Mcfd in 2000 to 2,580 Mcfd in 2001. Saddle Lake represented 43% of the Company's production in 2001. Five new wells, all successful, were drilled and tied in during the first and third quarters of 2001. A gas compression facility was constructed and commenced operations in the second quarter.

Geophysical work continued in 2001 with the purchase of 52 kilometres and the shooting of 29 kilometres of 2-D seismic. The interpretation of this data has identified many locations, at least five of which will be drilled in 2002. The Saddle Lake First Nation contains an additional 59 square miles of undrilled land available to the joint venture. Additional activity on these low risk exploration and development opportunities will increase production and replace declines over the next several years. The area offers multiple natural gas targets at relatively shallow depths of less than 700 metres.

Whitefish Lake

Approximately 32 kilometres (20 miles) north of Saddle Lake is the Whitefish Lake First Nation where the Company is a 50% partner in a permit under the joint venture with Keyano Pimee Exploration Company Ltd. This area contains three shut-in gas wells, two of which were drilled in 2001 and the third purchased at nominal cost.

Construction of a 4 MMcfd capacity compression facility together with ancillary gathering lines and a 14 kilometre sales pipeline is planned for 2002. This will allow TUSK to produce an estimated 1.8 MMcfd of net natural gas (300 boepd) from existing wells.

In 2001, TUSK shot 27 kilometres of 2-D seismic at Whitefish from which several locations have been identified. An additional 17 kilometres of 2-D seismic will be shot in 2002. The joint venture lands at Whitefish are only partially developed and 16 square miles of undrilled land are available for low risk exploration and development of multiple zone shallow gas targets.

Alexis

The Alexis First Nation is located approximately 60 kilometres (36 miles) northwest of Edmonton near Glenevis, Alberta. TUSK has a 37.5% interest in a 22 square mile permit in a joint venture arrangement with Alexis Oil & Gas Corp. (50% interest), a private company owned by the Alexis First Nation. Keyano Pimee Exploration Company Ltd. holds the remaining 12.5% as an industry partner.

The first TUSK well, drilled during the first half of 2001, was disappointing. Leads have been identified through further geological and geophysical work and at least one more exploratory well is anticipated in 2002.

Shane

This area approximately 70 kilometres (43 miles) northwest of Grande Prairie, Alberta was the site of a significant gas discovery during the first quarter of 2001. Two wells drilled during the year yielded a sizeable liquids rich Kiskatinaw zone sweet gas discovery and a dry hole. TUSK owns 17% in the gas well and 17% to 35% in 10 square miles of prospective land in the area.

The discovery well commenced production in late October 2001 after construction of gas processing and gathering facilities. The well produces approximately 10 MMcfd with 35 barrels of NGL per MMcf (340 boepd net).

Hartaven

Another area of significant production growth is the Hartaven area of southeast Saskatchewan located approximately 85 kilometres (54 miles) from each of the Manitoba and North Dakota borders in the Williston Basin. TUSK has working interests of 35% to 50% in 2,004 acres of petroleum rights.

Starting with the re-completion of an existing well in June 2001, a program of eight vertical and two horizontal wells of moderate depth was carried out. All were successful in developing oil reserves. Production treatment and water disposal facilities were added along with production gathering infrastructure resulting in attractive operating costs going forward.

TUSK's production grew from an average of 10 bopd in 2000 to 144 bopd average in 2001. Year-end production was over 500 bopd. One horizontal well was drilled in the first quarter of 2002 beginning a program of up to ten development wells for the year.

Meekwap

The sale of 40% of our holdings in Meekwap early in 2001 has resulted in the area having a less dominant position in the Company than in past years. Meekwap is located approximately 200 kilometres (130 miles) northwest of Edmonton near Whitecourt, Alberta.

At 175 boepd of high quality light oil with solution gas, Meekwap represented 17% of production in 2001 compared to 55% the previous year. One unsuccessful infill well was drilled in 2001.

Further drilling is anticipated in updip portions of the pool which have potential for incremental production and reserves.

Strachan

In west-central Alberta approximately 145 kilometres (90 miles) northwest of Calgary the Company owns interests of 25% to 65% in 27 square miles of land. The Company's average working interest of 36.3% includes the interests which were acquired from a partner in the third quarter of 2001.

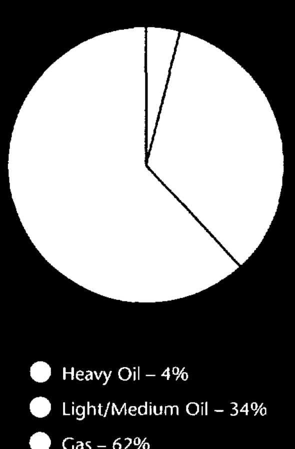
Net production from the 2-22-38-9W5 Slave Point zone (20% BPO, 35% APO) averaged 288 Mcfd in 2001 (5% of total production volumes) with little decline or downtime. TUSK has 41 square miles of 3-D seismic coverage over the Strachan lands. A well may be drilled in 2002 to evaluate targets defined by the 3-D program.

PRODUCTION

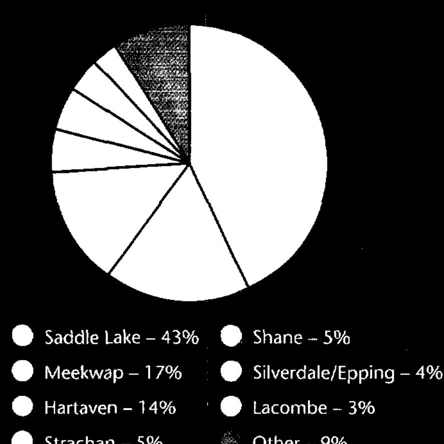
Over 90% of the Company's production comes from four areas, three in Alberta and one in Saskatchewan. The most significant growth area for TUSK was Heward/Hartaven, Saskatchewan which increased from less than 1% to 14% of our BOE production and Saddle Lake which increased from 14% to 43% of our BOE production. Gas production, which represented 62% of total BOE production, is primarily from Saddle Lake and Shane with lesser amounts from Carvel, Strachan and Meekwap.

Production has grown steadily over the past several years. Average production for the year was 404 bopd and 3,760 Mcfd (1,031 boepd), a 45% increase over the production levels of 2000 with a 165% increase in gas production.

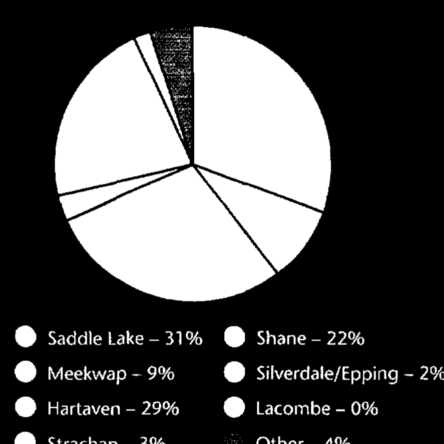
Production Summary



Production 2001



Production Exit



Reserves and Future Net Revenue

TUSK's reserves were evaluated at January 1, 2002 by Chapman Petroleum Engineering Ltd. an independent petroleum engineering firm.

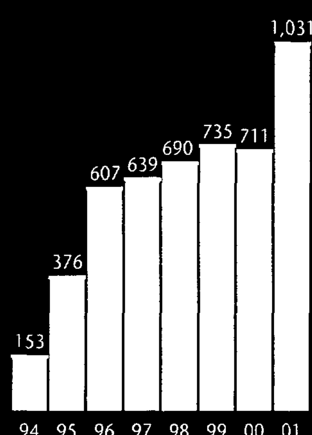
Crude oil and NGL reserves increased 1% from 2,204 Mbbls to 2,231 Mbbls and natural gas reserves increased 46% from 14,448 MMcf to 21,054 MMcf. Gas reserves reflect the discovery of 5,266 MMcf of gas, mainly at Saddle Lake, Whitefish and Shane and the acquisition of 2,582 MMcf at Saddle Lake and Strachan. Oil reserves from properties sold during the year and production volumes produced during the year have been replaced by new reserves developed at Hartaven. These reserves are gross proven and probable reserves (risked at 50%), net of production and revisions to prior year's estimates.

The present worth value before income taxes of the proven plus probable reserves (risked at 50%) at 15% discount factor is $44,950,000. These values were based on escalated price and cost assumptions as estimated by Chapman Petroleum Engineering Ltd. and do not necessarily represent the fair market value of the evaluated reserves.

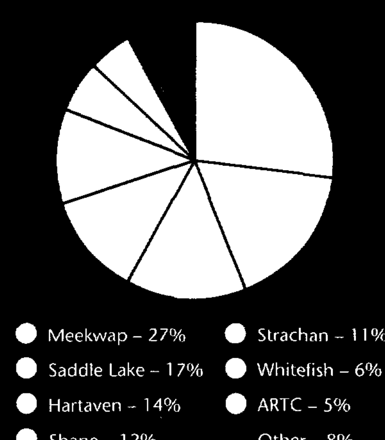
Estimated Reserves of Crude Oil and Natural Gas based on Escalated Pricing and Cost Assumptions at January 1, 2002

	Crude Oil & NGL's (Mbbls)		Natural Gas (MMcf)	
	Gross	**Net**	**Gross**	**Net**
Proven Developed Producing	1,452	1,118	9,853	7,579
Proven Developed Non-Producing	104	85	4,002	2,978
Proven Undeveloped	287	207	393	311
Total Proven	1,843	1,410	14,248	10,868
Probable (risked at 50%)	388	257	6,806	5,069
Total	**2,231**	**1,667**	**21,054**	**15,937**

Average Daily Production
(boepd)



Reserves Value
(proved + 50% probable)



Gross reserves are the Company's share of reserves and net reserves are gross reserves after deduction for crown, freehold and other royalties.

Discounted Value of Estimated Future Net Revenue before Income Taxes based on Escalated Price and Cost Assumptions at January 1, 2002

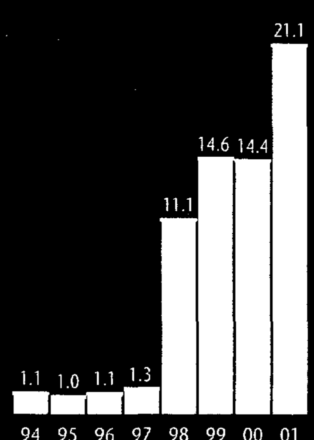
	Undiscounted (000's)	Discounted at 10% (000's)	Discounted at 15% (000's)	Discounted at 20% (000's)
Proven Developed Producing	$ 49,962	$ 33,775	$ 29,418	$ 26,198
Proven Developed Non-Producing	10,240	4,676	3,565	2,836
Proven Undeveloped	6,944	4,645	3,933	3,387
Total Proven	67,146	43,096	36,916	32,421
Probable (50%)	22,514	10,590	8,034	6,357
Total	**$ 86,660**	**$ 53,686**	**$ 44,950**	**$ 38,778**

Reserve Reconciliation (Before Royalties)

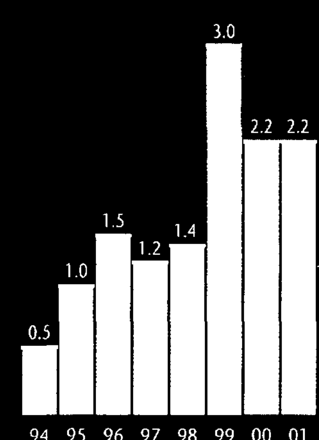
The following table provides the changes in TUSK's gross reserves based on escalated price and cost assumptions since January 1, 2001.

	Proven			Proven and 50% of Probables		
	Crude Oil & NGL's (Mbbls)	Natural Gas (MMcf)	Mboe (6:1)	Crude Oil & NGL's (Mbbls)	Natural Gas (MMcf)	Mboe (6:1)
January 1, 2001	1,692	8,709	3,144	2,204	14,448	4,611
Production	(148)	(1,372)	(376)	(148)	(1,372)	(376)
Discoveries	720	5,275	1,599	686	5,266	1,564
Purchases	–	1,675	279	9	2,582	439
Divestitures	(75)	(218)	(112)	(75)	(218)	(112)
Adjustments	(346)	179	(316)	(445)	348	(387)
December 31, 2001	1,843	14,248	4,218	2,231	21,054	5,739

Gas Reserves
Proved & 50% Risked Probables
(000's MMcf)



Oil Reserves
Proved & 50% Risked Probables
(000's Mbbls)



The engineering evaluation estimated WTI oil prices per barrel, in US dollars, of $22.00, $22.50, $23.75 and $25.00 for the years 2002 through 2005. Alberta spot gas prices were estimated in Canadian dollars at $3.61, $3.86, $4.11 and $4.11 per Mcf respectively over the same period. Both oil and gas prices were escalated at 3% thereafter. An annual cost inflation of 3% was assumed.

Reserve Life Index (Years)

December 31, 2001	Proven	Proven & 50% of Probables
Crude Oil & NGL's	12.5	15.1
Natural Gas	10.4	15.3
BOE's	11.2	15.3

Reserve Replacement Ratio

December 31, 2001	Proven	Proven & 50% of Probables
Crude Oil & NGL's	4.9	4.6
Natural Gas	3.8	3.8
BOE's	4.3	4.2

Finding and On-Stream Costs

	Year Ended December 31 2001 ($)	Year Ended December 31 2000 ($)	Year Ended December 31 1999 ($)	Year Ended December 31 1998 ($)
Finding Costs				
Land	1,981,516	1,151,365	494,518	807,132
Seismic and Other Exploration Costs	2,119,985	1,454,085	1,277,498	130,759
Drilling & Completion	4,693,569	3,233,530	2,192,201	2,704,152
Total	8,795,070	5,838,980	3,964,217	3,642,043
Well Equipment & Production Facilities	3,382,045	696,365	490,066	588,348
Total	12,177,115	6,535,345	4,454,283	4,230,391
Costs Per BOE				
Finding				
Proven	5.50	10.51	2.65	4.18
Proven Plus 1/2 Probable	5.62	10.39	2.09	1.71
On-Stream				
Proven	7.61	11.76	2.99	4.86
Proven Plus 1/2 Probable	7.79	11.62	2.35	1.98

Finding and on-stream costs increased significantly in 2001 and 2000, mainly due to our increased exploration focus with dramatic increases in our undeveloped land base and seismic and other exploration costs. In 2001, equipping and production facility costs increased due to the construction of the gas compressor facility at Saddle Lake and the construction of the plant and production facilities at Shane.

Asset Value Per Common Share

December 31, 2001
($ except Share Information)

Assets		
Working Capital		(1,226,789)
Proven and Probable Reserves (Risked at 50%) – (Escalated Pricing)		
(per Chapman Petroleum Engineering Ltd. Reserve Report @15% DCF BTAX)		44,950,000
Undeveloped Land (54,983 net acres @$75/Acre)		4,123,725
Other Assets, Net		1,658,757
		49,505,693
Liabilities		
Long-Term Debt		(14,221,115)
Future Site Restoration Provision		(333,462)
Net Asset Value	$	34,951,116
Common Shares Outstanding December 31, 2001		15,953,774
NAV per Common Share	$	2.19

Summary of Information per BOE

	Year Ended December 31 2001 ($)	Year Ended December 31 2000 ($)
Gross Revenue	27.73	34.76
Royalties, Net of ARTC	4.74	8.55
Net Revenue	22.99	26.21
Operating Expense	5.52	7.87
Net Operating Revenue	17.47	18.34
General & Administrative	2.40	2.65
Interest Expense	1.71	1.88
Current Income Taxes	0.27	0.16
Cash Flow per boe	13.09	13.65

Accounting & Finance

Gord Case
Vice President

Dave Krause
Production Accountant

Maria Nicholson
Accounting Clerk

Nora Ring
Controller

Engineering & Production

Ed Beaman
Vice President

Jim Boyd
Engineer

Casey Makokis
Junior Field Operator

Russ Scarlett
Field Supervisor

Exploration & Land

Rob Armstrong
Geological Technician

Warren Blair
Landman

Ian Brown
Vice President

Colin Chen
Geologist

Carol Gaskin
Land Administrator

Jean MacLean
Landman

Dave Slessor
Geologist

Darol Turnquist
Geologist

Corporate

Wayne Jessee
Vice President

Roxanne Hartwick
Receptionist/Secretary

Norm Holton
President

Michele Wiltshire
Executive Assistant

TUSK ENERGY INC.

MANAGEMENT'S FINANCIAL ANALYSIS & DISCUSSION

The following discussion is presented in conjunction with the consolidated financial statements and accompanying notes.

OIL AND GAS REVENUES

Oil and gas revenue before royalties, for the year ended December 31, 2001 was $10,273,714 compared to $9,025,205 for the year ended December 31, 2000, a 14% increase. This was due to a $8.69 per barrel decrease in the average oil price and a $1.31/Mcf decrease in the price of gas in 2001, more than offset with a 45% increase in BOE production from 259,643 BOE to 376,314 BOE.

Oil and Gas Revenues

	Year Ended December 31 2001	Year Ended December 31 2000
Oil and Gas Revenues, Before Royalties	$ 10,273,714	$ 9,025,205
Oil Production (bbls)	147,574	173,426
Oil Price ($/bbl)	$ 23.42	$ 32.11
Gas Production (MMcf)	1,372	517
Gas Price ($/Mcf)	$ 4.96	$ 6.27
BOE Production	376,314	259,643
BOE per Day	1,031	711

ROYALTIES

The total royalties, net of ARTC, were $1,784,440 ($4.74 per BOE) for the year ended December 31, 2001 compared to $2,219,415 ($8.54 per BOE) for the year ended December 31, 2000.

Net royalties were lower mainly due to the sale of a portion of the Meekwap D-2A Unit at December 31, 2000, which had mostly higher royalty rates and the drilling at Hartaven where production had Saskatchewan royalty holidays for the new wells.

Royalty Summary

	Year Ended December 31 2001 ($)	Year Ended December 31 2000 ($)
Crown Royalties	651,806	1,909,226
Indian Oil & Gas Canada Royalties	910,635	362,993
Freehold Royalties	218,705	106,255
Gross Overriding Royalties	113,775	111,426
	1,894,921	2,489,900
Alberta Royalty Tax Credit	(110,481)	(270,485)
Net Royalties	1,784,440	2,219,415
Net Royalties per BOE	4.74	8.54

OPERATING EXPENSES

Operating expenses in calendar 2001 were $2,079,339 ($5.52 per BOE) compared to $2,043,410 ($7.87 per BOE) in fiscal 2000. The sale of a portion of the Company's interest in the Meekwap

D-2A Unit effective December 31, 2000, which had high operating costs per barrel and the construction of the Company's own gas compressor plant at Saddle Lake, which lowered operating fees, were the main reason for lower operating expenses.

DEPLETION, DEPRECIATION AND AMORTIZATION

Depletion, depreciation and amortization was $2,889,350 for the year ended December 31, 2001, which represents a provision of $7.54 per BOE of production. For the year ended December 31, 2000, the Company recorded a depletion, depreciation and amortization provision of $1,644,700 ($6.34 per BOE).

GENERAL AND ADMINISTRATIVE

Gross general and administrative costs increased from $1,599,608 in 2000 to $1,934,283 mainly due to the hiring of additional exploration personnel during the latter part of 2000 which were on staff for the entire year 2001.

	Year Ended December 31 2001 ($)	Year Ended December 31 2000 ($)
Gross General and Administrative	1,934,283	1,599,608
Acquisition, Exploration & Development Costs Capitalized	(544,000)	(416,120)
Overhead Recoveries	(488,632)	(495,819)
Net General and Administrative	901,651	687,669
Per BOE	$ 2.40	$ 2.65

EQUITY

In October, 2001 the Company issued 3,400,000 flow-through common shares in a private placement at a price of $1.00 per common share.

The Company purchased 523,000 common shares under normal course issuer bids during the fiscal year at a total cost of $422,620. In addition, 1,562,656 common shares were purchased under exempt issuer bids at a cost of $1,514,122. Average cost of the 2,085,656 cancelled shares was $0.93.

ACQUISITIONS AND DIVESTITURES

Auburn Energy Ltd. (a wholly-owned subsidiary of TUSK) acquired all of the issued and outstanding shares of Spirit Energy Ltd. effective April 30, 2001 for $2.97 million cash, plus the payment of $500,000 for net working capital at closing. Spirit's assets are a 10% interest in 14 producing and shut-in gas wells on the Saddle Lake First Nation, a 10% interest in two shut-in gas wells on the Whitefish Lake First Nation and rights to participate, with Auburn, in joint ventures with the Saddle Lake and Whitefish Lake First Nations.

The Company sold five minor properties in December 2001 for $871,000.

CAPITAL EXPENDITURES

Capital additions, excluding acquisitions and divestitures, for the year ended December 31, 2001 were $12,257,399 compared to $6,569,268 for the year ended December 31, 2000.

	Year Ended December 31 2001 ($)	Year Ended December 31 2000 ($)
Land	1,981,516	1,151,365
Seismic & Exploration	2,119,985	1,454,085
Drilling & Completion	4,693,569	3,233,530
Facilities	3,382,045	696,365
Corporate	80,284	33,923
Total	12,257,399	6,569,268

LIQUIDITY AND CAPITAL RESOURCES

TUSK had a working capital deficiency of $1,226,789 at December 31, 2001.

The Company has a financing arrangement with a Canadian financial institution whereby the Company has been provided a $15.0 million revolving production loan. $13,850,000 of the revolving production loan was drawn at December 31, 2001. Subsequent to December 31, 2001, the Company negotiated a revision to the credit facility to a revolving loan in the amount of $18,000,000 with monthly borrowing base reductions of $500,000 to commence May 1, 2002.

BUSINESS RISKS

The marketability and price of products owned or that may be acquired or discovered by TUSK will be affected by numerous factors beyond the Company's control. TUSK must compete in all aspects of its operations with a number of other corporations that have equal or greater technical or financial resources. The ability of the Company to market its natural gas may depend on its ability to acquire space in pipelines that deliver natural gas to commercial markets. The Company is also subject to market fluctuations in the prices of products, exchange rates, deliverable uncertainties related to the proximity of its reserves to pipelines and processing facilities and extensive government regulation.

SHARE TRADING INFORMATION

		2001			
	Full Year	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High ($/share)	1.35	0.96	1.09	1.35	0.81
Low ($/share)	0.56	0.78	0.75	0.72	0.56
Close ($/share)	0.90	0.90	0.81	0.93	0.75
Volume	5,440,594	929,581	1,160,077	1,976,670	1,374,266
Value ($)	4,812,056	801,953	1,048,570	2,010,006	951,527

QUARTERLY DATA (UNAUDITED)

A quarterly summary of the key financial results reported in the 12 months ending December 31, 2001 are as follows:

	Fourth Quarter ($)	Third Quarter ($)	Second Quarter ($)	First Quarter ($)
Oil & Gas Revenue, Net of Royalties	2,736,698	1,861,343	2,040,821	2,012,255
Net Income (Loss)	114,088	245,021	446,214	486,866
Net Income (Loss) Per Share	0.01	0.01	0.04	0.03
Cash Flow	1,503,838	987,121	1,204,314	1,229,666
Cash Flow Per Share	0.10	0.07	0.08	0.09
Annualized Cash Flow	0.40	0.28	0.32	0.36
BOE's per Day	1,444	1,061	838	648

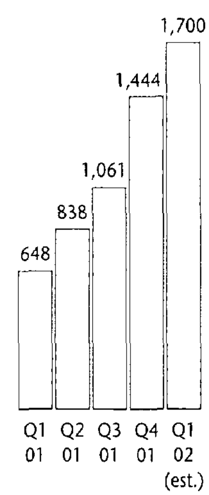
INCOME TAX POOLS (UNAUDITED)

The consolidated income tax pools for the Company and its subsidiaries estimated as of December 31, 2001 are as follows:

	$
Canadian Exploration Expense	4,597,000
Canadian Development Expense	1,767,000
Canadian Oil & Gas Property Expense	3,151,000
Mining Depletion	30,000
Foreign Exploration and Development	302,000
Undepreciated Capital Costs	3,825,000
Business Losses	4,000
Share Issue Expenses	701,000
	14,377,000

Based on the Company's budgeted capital expenditures and budgeted revenue and expenses, the Company does not expect to be taxable in 2002.

Average Daily Production
(boepd)



MANAGEMENT'S REPORT

Management is also responsible for maintaining a system of internal control designed to provide reasonable assurance that assets are safeguarded and that accounting systems provide timely, accurate and reliable financial information.

The board of directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The board is assisted in exercising its responsibilities through the audit committee of the board, which includes three non-management directors. The audit committee meets periodically with management and the auditors to satisfy approval of the financial statements to the board.

KPMG LLP, the independent auditors appointed by the shareholders, have audited the Company's financial statements in accordance with generally accepted auditing standards and their report follows. The independent auditors have full and unrestricted access to the audit committee to discuss their audit and their related findings as to the integrity of the financial reporting process.

[Signed]

Norman W. Holton
President and Chief Executive Officer
March 14, 2002

[Signed]

Gordon K. Case
Vice President and Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of TUSK Energy Inc.

We have audited the consolidated balance sheets of TUSK Energy Inc. as at December 31, 2001 and 2000 and the consolidated statements of operations and retained earnings (deficit) 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 at December 31, 2001 and 2000 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

[Signed]

KPMG LLP
Chartered Accountants

Calgary, Canada
March 1, 2002

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31 2001 ($)	December 31 2000 ($)
Current Assets		
Cash	**17,586**	17,257
Accounts Receivable	**2,203,978**	4,635,004
Properties Sale Proceeds Receivable	**–**	3,900,000
Prepaid Expenses and Deposits	**71,175**	101,796
	2,292,739	8,654,057
Loans to Officers and Directors *(Note 2)*	**832,511**	832,511
Investment *(Note 3)*	**826,246**	226,246
Deferred Charges *(Note 11)*	**52,000**	104,000
Capital Assets *(Note 5)*	**36,397,539**	23,246,144
	40,401,035	33,062,958

LIABILITIES AND SHAREHOLDERS' EQUITY

	December 31 2001 ($)	December 31 2000 ($)
Current Liabilities		
Accounts Payable and Accrued Liabilities	**3,456,022**	6,977,322
Current Portion of Long-Term Debt *(Note 6)*	**63,506**	3,900,000
	3,519,528	10,877,322
Long-Term Debt *(Note 6)*	**14,221,115**	4,350,000
Future Site Restoration	**333,462**	283,062
Future Income Taxes *(Note 9)*	**9,448,875**	5,912,249
Shareholders' Equity		
Capital Stock *(Note 7)*	**10,516,024**	9,991,483
Retained Earnings	**2,362,031**	1,648,842
	12,878,055	11,640,325
Commitments and Contingencies *(Note 10)*		
	40,401,035	33,062,958

Approved on Behalf of the Board:

[Signed] *[Signed]*

Norman W. Holton, Director James E. Lawson, Director

See Accompanying Notes

CONSOLIDATED STATEMENT OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

	For the Year Ended December 31 2001	For the Year Ended December 31 2000
	($)	($)
Revenue		
Oil and Gas Revenues, Net	8,651,117	6,805,788
Expenses		
Oil and Gas Operating	2,079,338	2,043,410
Interest on Long-Term Debt	642,363	487,087
Provisions for Future Site Restorations	50,400	27,600
General and Administrative	901,651	687,669
Depreciation, Depletion and Amortization	2,889,350	1,644,700
	6,563,102	4,890,466
Net Income for the Year Before Future Taxes	2,088,015	1,915,322
Current Income Taxes	102,826	42,730
Future Income Taxes *(Note 9)*	693,000	964,000
	795,826	1,006,730
Net Income For the Year	1,292,189	908,592
Retained Earnings (Deficit), Beginning of Year	1,648,842	(646,750)
Adjustment for Share Redemption	(579,000)	–
Change in Accounting Policy Related to Future Income Taxes *(Note 8)*	–	1,387,000
Retained Earnings, End of Year	2,362,031	1,648,842
Net Income per Share *(Note 12)*		
Basic	0.09	0.06
Diluted	0.09	0.06

See Accompanying Notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31 2001	For the Year Ended December 31 2000
	($)	($)
Operating Activities		
Operations:		
Net Income	1,292,189	908,592
Add:		
Items not Requiring Cash		
- Provision for Future Site Restorations	50,400	27,600
- Depreciation, Depletion and Amortization	2,889,350	1,644,700
- Future Income Taxes	693,000	964,000
Funds from Operations	4,924,939	3,544,892
Change in Non-cash Working Capital	947,058	44,661
	5,871,997	3,589,553
Financing Activities		
Issue of Capital Stock	3,428,000	–
Share Issue Costs	(112,717)	(162,288)
Repurchase of Common Shares	(1,936,742)	(1,004,012)
Long-Term Debt	6,034,621	4,350,000
	7,413,162	3,183,700
Investing Activities		
Oil and Gas Properties	(12,177,115)	(6,535,345)
Proceeds on Sales of Oil and Gas Properties	870,745	6,538,591
Acquisition of Subsidiary, Net of Cash Acquired	(2,953,904)	(3,261,546)
Loans to Officers and Directors	–	(832,511)
Investments	(600,000)	(36,596)
Furniture and Equipment	(80,284)	(33,923)
Change in Non-Cash Working Capital	1,655,728	(2,618,136)
	(13,284,830)	(6,779,466)
Increase in Cash During the Year	329	(6,213)
Cash: Beginning of Year	17,257	23,470
Cash: End of Year	17,586	17,257
Funds from Operations per Share *(Note 12)*		
Basic	0.34	0.25
Diluted	0.33	0.25

See Accompanying Notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES

a) Basis of Presentation:

These consolidated financial statements include the accounts of the Company's wholly-owned subsidiaries, Auburn Energy Ltd., Spirit Energy Ltd., New Quebec Platinum Inc., TUSK Oil Corporation and 416600 Alberta Inc.

b) Oil and Gas Properties:

The Company follows the full cost method of accounting in accordance with the guidelines issued by the Canadian Institute of Chartered Accountants, whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized. All such costs are accumulated in a single cost centre representing the Company's activities. Such costs include land acquisitions, drilling and geological and geophysical expenses related to exploration and development activities. Gains or losses are not recognized upon disposition of oil and gas properties unless crediting the proceeds against accumulated costs would result in a significant change in the rate of depletion.

Costs capitalized in the cost centre, plus a provision for future development costs of proved undeveloped reserves, are depleted using the unit-of-production method, based on estimated proven oil and gas reserves, before royalties, as determined by independent consulting engineers. For purposes of the depletion calculation, oil and gas reserves are converted to a common unit of measure on the basis of their relative heating value. The carrying value of undeveloped properties is excluded in the depletion calculation.

In applying the full cost method, the Company performs a ceiling test which limits the capitalized costs less accumulated depletion and depreciation to an amount equal to the estimated undiscounted value of future net revenues from proven oil and gas reserves, based on year-end prices and costs, and after deducting estimated future general and administrative expenses, future abandonment and site restoration costs, financing costs and income taxes.

The Company periodically reviews the costs associated with undeveloped properties to determine whether the costs will be recoverable. An impairment allowance is made if the results of the review indicate an impairment has occurred.

Estimated future abandonment and site restoration costs are provided for using the unit-of-production method based upon estimated proven reserves. Removal and site restoration expenditures are charged to the accumulated provision account as incurred.

c) Joint Ventures:

Substantially all of the Company's oil and gas activities are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities.

d) Per Share Amounts:

Per share amounts have been calculated using the weighted average number of common shares outstanding during the year. Diluted per share amounts have been calculated using the treasury stock method.

e) Measurement Uncertainty:

The amounts recorded for depletion and depreciation of capital assets and the provision for future abandonment and site restoration costs are based on estimates. The ceiling test is based on such factors as estimated proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

f) Hedging Transactions:

The Company periodically used certain financial instruments to hedge its exposure to commodity price and foreign exchange fluctuations on a portion of its crude oil and natural gas sales. Gains and losses on these transactions are reported as adjustments to revenue when the hedged production is sold.

g) Income Taxes:

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the current enacted tax rates in effect. The Corporation changed to the liability from the deferral method effective January 1, 2000. *(See Note 8)*

h) Stock Options:

The Company has a stock option plan as described in note 7. When stock options are issued the value of the options is not determined or recorded. Any consideration received on the exercise of stock options credited to share capital.

2. LOANS DUE FROM OFFICERS AND DIRECTORS

In 2000 the Company loaned $832,511 to certain officers and directors to purchase common shares of the Company in a market transaction at a price of $0.85 per share. The loans are for a term of three years beginning April 10, 2000, bear interest at a rate of 5% per annum and are secured by the purchased shares. Under the terms of the lending agreement, if the loan becomes due and the sale of the purchase shares is not sufficient to repay the loan and any accrued interest, the borrower must pay the shortfall. Subsequent to December 31, 2001 $227,205 of the loan was repaid by certain officers and directors.

3. INVESTMENT

The Company has invested a total of $826,246 in Loon Energy Inc. ("Loon"), an oil and gas company which is listed on the Canadian Venture Exchange, $226,246 in the form of 1,925,939 common shares and $600,000, in the form of a convertible subordinated debenture due July 27, 2003 bearing interest at 2% above the company's bank's prime lending rate. The debenture is convertible at 10 common shares for $1 of debenture.

On August 31, 2001, the Company closed the acquisition of oil and gas properties from Loon at a fair market value of $785,629. One officer and director of the Company is an officer and director of Loon.

For the year ended December 31, 2000, $300,000 in the form of a demand note payable bearing interest at 1% above the Company's bank's prime lending rate was included in accounts receivable.

4. ACQUISITION OF SPIRIT ENERGY LTD.

On April 13, 2001 the Company acquired all of the issued and outstanding shares of Spirit Energy Ltd., a private company engaged in the exploration for and production of natural gas and crude oil in Western Canada.

The acquisition has been accounted for by the purchase method of accounting as follows:

Consideration given	$
Cash	3,468,300
Transaction Costs	40,463
Total Cash Consideration	3,508,763
Allocation of Purchase Price	
Capital Assets	4,602,092
Future Income Taxes	(1,410,626)
Net Capital Assets	3,191,466
Working Capital	317,297
	3,508,763

5. CAPITAL ASSETS

	December 31, 2001		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	($)	($)	($)
Oil and Gas Properties	51,862,805	15,665,932	36,196,873
Furniture and Equipment	401,489	200,823	200,666
	52,264,294	15,866,755	36,397,539

	December 31, 2000		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	($)	($)	($)
Oil and Gas Properties	35,962,499	12,867,932	23,094,567
Furniture and Equipment	313,050	161,473	151,577
	36,275,549	13,029,405	23,246,144

During the year administrative overhead expenditures of $544,000 (2000 - $416,000) directly related to the acquisition, exploration and development of petroleum and natural gas reserves have been capitalized. No interest has been capitalized to oil and gas properties in either of the years ended December 31, 2001 or 2000. The depletion calculation has excluded unproved properties of $2,133,000 (2000 - $3,600,000).

As at December 31, 2001, the estimated future site restoration costs to be accrued over the remaining proved reserves are $511,000 (2000 - $356,000).

6. LONG-TERM DEBT

	2001 ($)	2000 ($)
Bank Credit Facility	13,850,000	8,250,000
Capital Lease	434,621	–
	14,284,621	8,250,000
Less: Current Portion	63,506	3,900,000
	14,221,115	4,350,000

a) The credit facility is a revolving loan in the amount of $15,000,000 and bears interest at the bank's prime lending rate plus 0.125%. The loan is secured by a $20,000,000 floating charge debenture over the majority of the assets of the Company and a general security agreement covering all present property of the Company. The terms of the credit facility call for monthly principal repayments of $600,000 to commence on February 28, 2002. Subsequent to December 31, 2001, the Company negotiated a revision to the credit facility to a revolving loan in the amount of $18,000,000 with monthly borrowing base reductions of $500,000 to commence May 1, 2002, bearing interest at the bank's prime lending rate plus 0.25%. The bank does not foresee requiring borrowing base reductions greater than $4,000,000 providing the Company continues to satisfy the provisions of the credit agreement, and consequently the debt has been classified as long-term.

b) The capital lease is repayable over 60 months, bears interest at 8.5% per annum and has $434,621 remaining outstanding at December 31, 2001.

7. CAPITAL STOCK

a) **Authorized:**

The Company has authorized capital of:

- an unlimited number of common shares without nominal or par value.
- an unlimited number of first and second preferred shares issuable in series with rights, privileges and conditions to be determined by the Board of Directors.

b) **Issued**

Common shares and Special Warrants were issued as follows:

	December 31, 2001		December 31, 2000	
	Number	Amount ($)	Number	Amount ($)
Balance Beginning of Year	14,599,430	9,991,483	13,697,234	8,740,455
Issued for Cash:				
Exercise of Stock Options	40,000	28,000	–	–
Issued for Purchase of Subsidiary	–	–	2,302,196	1,602,328
Issuance of Flow-Through Common Shares	3,400,000	3,400,000	–	–
Less: Tax Effect of Flow-Through Shares	–	(1,483,000)	–	–
Repurchased under Normal Course Issuer Bid	(523,000)	(348,620)	(1,400,000)	(1,004,012)
Repurchased under Exempt Issuer Bids	(1,562,656)	(1,009,122)	–	–
	15,953,774	10,578,741	14,599,430	9,338,771
Change in Accounting Policy Related to Future Income Taxes *(Note 7)*	–	–	–	743,000
Less: Share Issue Expenses, Net of Tax Effect	–	(62,717)	–	(90,288)
Balance End of Year	15,953,774	10,516,024	14,599,430	9,991,483

c) **Normal Course Issuer Bid:**

Under a Normal Course Issuer bid, the Company received approval in January 2001 to purchase up to 1,257,000 of its outstanding common shares until January 28, 2002. A total of 478,000 common shares at a cost of $395,210 were purchased under the plan in 2001.

Under a Normal Course Issuer Bid, the Company received approval in January 2000 to purchase up to 1,257,000 of its outstanding common shares until January 25, 2001. A total of 1,212,000 shares at a cost of $855,132 were purchased under the plan in 2000 and a total of 45,000 at a cost of $27,410 were purchased for the period January 1, 2001 to January 25, 2001.

A total of 523,000 common shares were purchased in 2001 at a total cost of $422,620, $74,000 of this cost was charged to retained earnings and $348,620 was charged to share capital.

The Company received approval in February, 2002 to purchase up to 1,363,500 of its outstanding common shares until February 10, 2003.

Subsequent to December 31, 2001 the Company has acquired 17,100 common shares at a cost of $17,012 until March 1, 2002 under the issuer bid approved February 2002.

d) **Exempt Issuer Bids**

On March 7, 2001, the Company acquired 512,000 common shares from an arm's length party. Total consideration was $358,400 or $0.70 per share.

On December 10, 2001 the Company acquired 1,050,656 common shares from two arm's length parties. Total consideration was $1,155,722 or $1.10 per share.

A total of 1,562,656 common shares were purchased in 2001 at a total cost of $1,514,122, $505,000 of this cost was charged to retained earnings and $1,009,122 was charged to share capital.

e) **Stock Options**

Stock options, entitling the holder to purchase shares from the Company, have been granted to directors, officers and certain employees of the Company. The stock options vest and are exercisable immediately following the grant of the options.

A summary of the status of the Company's stock option plan as of December 31, 2001 and 2000, and changes during the years ending on those dates is presented below.

		2001		2000
	Options	Weighted Average Exercise Price ($)	Options	Weighted Average Exercise Price ($)
Outstanding at Beginning of Year	1,995,000	0.85	1,459,000	0.98
Granted	250,000	1.00	908,000	0.74
Exercised	(40,000)	0.70	–	–
Expired/Cancelled	(205,000)	0.96	(372,000)	1.10
Outstanding and Exercisable at End of Year	2,000,000	0.86	1,995,000	0.85

The following table summarizes information regarding stock options outstanding at December 31, 2001:

Options Outstanding

Exercise Price ($)	Number Outstanding	Weighted Average Remaining Contractual Life
0.70	548,000	3.5
0.80	360,000	3.6
0.90	663,000	2.5
1.00	250,000	4.5
1.10	149,000	1.0
1.25	30,000	0.5
	2,000,000	3.1

f) **Shareholder Protection Rights Plan:**

A Shareholder Protection Rights Plan (the "Rights Plan") was approved at the Annual and Special Shareholders Meeting May 29, 2001. The Rights Plan utilizes the mechanism of the Permitted Bid to ensure that a person seeking control of the Corporation (an "Acquiring Person") allows shareholders and the Board of Directors sufficient time to evaluate the bid. The purpose of the Permitted Bid (a bid which provides that shares tendered to the bid will not be taken up prior to 60 days following the date of the bid) is to encourage a potential bidder to avoid the dilutive features of the Rights Plan by making a Permitted Bid or by negotiating with the Directors the terms of an offer which is fair to all shareholders.

If a Take-Over Bid does not qualify as a Permitted Bid the Rights Plan provides that shareholders other than the Acquiring Person may purchase shares at a reduced price, thereby diluting the value of the Acquiring Person's shares.

8. CHANGE IN ACCOUNTING FOR FUTURE INCOME TAXES

Effective January 1, 2000, the liability method was adopted; prior thereto, the company followed the deferral method of accounting for income taxes. The new method was applied retroactively without restatement of prior period financial statements. At January 1, 2000, the future income tax liability was increased by $1,065,000, retained earnings was increased by $1,387,000, share capital was increased by $743,000 and property, plant and equipment was increased by $3,195,000. These adjustments were a result of the future tax cost recognition of the impact of the issue of flow-through shares.

9. INCOME TAXES

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory rate of 43.0% (2000 - 44.6%) to income before income taxes. The reasons for the differences are as follows:

	Year Ended December 31 2001	Year Ended December 31 2000
	($)	($)
Expected Income Tax Expense	898,350	854,200
Non-deductible Crown Charges	280,400	850,700
Alberta Royalty Tax Credit	(47,500)	(120,600)
Resource Allowance	(562,900)	(618,500)
Capital Taxes	102,826	40,000
Previously Unrecorded Tax Basis	124,650	930
Actual Income Tax Expense	795,826	1,006,730

The components of the future tax liability at December 31, 2001 is as follows:

	Year Ended December 31, 2001
	($)
Capital Assets	(9,858,175)
Share Issue Costs	301,700
Site Restoration	107,600
	(9,448,875)

10. COMMITMENTS AND CONTINGENCIES

a) The Company entered into an agreement to lease office space for six years beginning January 1, 1997 for approximately $240,000 per year. A portion of the office space is subleased for approximately $120,000 per year. The sublease can be terminated by either party after six months notice.

b) The Company has been named in a statement of claim, for an unspecified amount, filed by a joint venture partner against the Company and the previous operator of the Meekwap East Flank Pool alleging that the defendants had failed to account for the joint venture partner's share of revenues from the east flank lands. The amount of the liability, if any, can not be determined at this time.

c) At December 31, 2001 the Company has a commitment to renounce a further $1,830,000 of tax attributes associated with exploratory and development activities.

11. HEDGING TRANSACTIONS

The following hedging contracts were outstanding at December 31, 2001:

a) The Company has entered into a costless collar agreement for 200 barrels per day of oil production for the period from January 1, 2002 to December 31, 2002 at a price range of $17.00 US to $23.75 US per barrel. The estimated market value of this contract at December 31, 2001, had it been settled at that time, would result in a payment of $43,258.

b) The Company has entered into a costless collar agreement for 2000 GJ's per day of gas production for the period from May 1, 2001 to December 31, 2002 at a price range of $5.00 Cdn. To $10.68 Cdn. per GJ. The estimated market value of this contract at December 31, 2001, had it been settled at that time, would result in a gain of $1,105,200.

c) The Company entered into a foreign exchange which was cancelled August 20, 1999 at a net payment of $331,000. Of that amount, $175,000 of the payment was expensed and the balance of the payment ($156,000) has been deferred and is being amortized over a three year period, beginning January 1, 2000, which represents the original term of the foreign exchange rate arrangement.

Effective February 29, 2002, the Company entered into a costless collar agreement for 200 barrels per day of oil production for the period March 1, 2002 to December 31, 2002 at a price range of $17.00 US to $25.10 US per barrel. Effective March 1, 2002, the Company fixed a floor price of $17.00 US for an additional 200 barrels per day for the period March 1, 2002 to December 31, 2002 at a cost of US $38,556.

12. PER SHARE AMOUNTS

The Canadian Institute of Chartered Accountants has approved a new standard for the computation, presentation and disclosure of earnings per share. In the fourth quarter of fiscal 2000, the Company retroactively adopted the new standard. Under the new standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

In computing diluted earnings and cash flow from operations per share, 148,677 shares were added to the weighted average number of common shares outstanding during the year December 31, 2001 (2000 - 6,670 shares) for the dilutive effect of employee stock options. No adjustments were required to reported earnings or cash flow from operations in computing diluted per share amounts.

TEN YEAR REVIEW

	Years Ended December 31							Nine Months Ended December 31	Years Ended March 31	
	2001	2000	1999	1998	1997	1996	1995	1994	1994	1993
Revenue										
Oil & Gas Revenues, Net	**8,651,117**	6,805,788	5,086,350	4,103,157	4,633,819	4,065,606	2,277,728	793,672	685,913	3,151
Expenses										
Oil & Gas Operating	**2,079,338**	2,043,410	1,543,624	1,373,765	1,376,455	1,104,612	613,938	308,334	267,409	–
Interest on Long-Term Debt	**642,363**	487,087	277,071	271,490	299,508	283,940	190,695	152,710	22,740	–
Provision for Site Restoration	**50,400**	27,600	42,100	44,997	63,500	67,800	33,500	7,000	8,000	–
General & Administrative	**901,651**	687,669	672,049	474,728	406,279	458,860	270,139	239,757	189,846	101,759
Depreciation and Depletion	**2,889,350**	1,644,700	1,386,100	1,536,100	5,688,700	1,449,180	636,200	507,500	1,248,650	722
Loss on Foreign Exchange	–	–	175,000	–	–	–	–	–	–	–
Loss on Disposition of Oil and Gas Property	–	–	–	–	–	–	–	3,590,401	–	–
Property Impairment	–	–	–	–	73,080	–	–	–	636,432	12,139
	6,563,102	4,890,466	4,095,944	3,701,080	7,907,522	3,364,392	1,744,472	4,805,702	2,373,077	114,620
Income Taxes	**795,826**	1,006,730	–	–	–	–	–	–	–	–
Net Income (Loss)	**1,292,189**	908,592	990,406	402,077	(3,273,703)	701,214	533,256	(4,012,030)	(1,687,164)	(111,469)
Cash Flow from Operations	**4,924,939**	3,544,892	2,418,606	1,983,174	2,551,577	2,218,194	1,202,956	92,871	205,918	(98,608)
Balance Sheet										
Working Capital (Deficiency)	**(1,226,789)**	(2,223,265)	(44,859)	(430,714)	(149,368)	613,267	305,893	(167,553)	(1,735,206)	(2,386)
Other Assets	**1,710,757**	1,162,757	480,851	145,632	–	–	–	–	–	–
Capital Assets	**36,397,539**	23,246,144	11,945,325	10,767,247	9,277,403	12,090,657	4,434,993	3,848,830	7,798,110	753,928
Long-Term Debt	**14,221,115**	4,350,000	3,900,000	4,338,327	4,257,341	5,385,655	1,662,500	1,600,000	660,000	–
Future Site Restoration	**333,462**	283,062	252,411	210,311	169,800	106,300	38,500	5,000	8,000	–
Future Income Taxes	**9,448,875**	5,912,249	–	–	–	–	–	–	–	–
Shareholders' Equity	**12,878,055**	11,640,325	8,093,705	6,268,746	4,846,526	7,211,969	3,039,886	2,076,277	5,394,904	751,542
Per Share Data										
Net Income (Loss) per Share	**0.09**	0.06	0.08	0.04	(0.41)	0.14	0.13	(1.10)	(1.40)	(0.20)
Cash Flow per Share	**0.34**	0.25	0.20	0.20	0.32	0.44	0.29	0.03	0.18	(0.16)
Production										
Oil (Bopd)	**389**	475	562	603	554	455	307	153	146	–
Gas (Mcfd)	**3,760**	1,417	1,036	519	509	910	416	–	–	–
Reserves (Proven & Probable)										
Oil (Mbbls)	**2,618**	2,516	3,486	1,788	1,516	1,777	1,217	558	832	–
Gas (MMcf)	**27,859**	20,187	21,801	18,061	1,650	1,323	1,098	1,138	1,029	–

BOARD OF DIRECTORS

William E. Code, QC [1][2][3]
Calgary, Alberta

Norman W. Holton
Calgary, Alberta

James E. Lawson, CA[1][2][3]
Calgary, Alberta

John D. Morgan[1][3]
Montreal, Quebec

(1) Audit Committee
(2) Reserve Evaluation Committee
(3) Compensation Committee

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President & Chief Executive Officer

Gordon K. Case, CA
Vice President & Chief Financial Officer

Ian T. Brown, P. Geol.
Vice President, Exploration

Ed A. Beaman, P. Eng.
Vice President, Production & Engineering

Wayne B. Jessee, P. Eng.
Vice President, Corporate Development

Brian W. Mainwaring
Secretary

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