Paramount Resources Ltd.

Paramount Resources Ltd.: Financial and Operating Results for the Period Ended December 31, 2003

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CALGARY, ALBERTA - Mar 24, 2004 /CNW/ - Paramount Resources Ltd. ("Paramount" or the "Company") is pleased to announce its financial and operating results for the year ended December 31, 2003.

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2003 Financial Highlights

($ thousands except per share amounts and where stated otherwise)	Three Months Ended December 31, 2003	2002	% Change
FINANCIAL			
Gross Revenue	88,361	138,337	(36)%
Cash Flow			
From operations	43,157	62,102	(31)%
Per share - basic	0.72	1.04	(31)%
- diluted	0.71	1.04	(32)%
Earnings			
Net earnings	11,296	(41,399)	-
Per share - basic	0.18	(0.70)	-
- diluted	0.18	(0.70)	-
Capital expenditures			
Exploration and development	84,500	14,047	502%
Summit acquisition	-	-	-
Acquisitions, dispositions and other	(43,869)	(3,329)	1,218%
Net capital expenditures	40,631	10,718	279%
Total assets			
Net debt			
Shareholders' equity			
Weighted average common shares outstanding (thousands)			
Common shares outstanding at year end (thousands)			
Common shares outstanding at March 12, 2004 (thousands)			
OPERATING			
Production			
Natural gas (MMcf/d)	141	263	(46)%
Crude oil and liquids (Bbl/d)	5,877	8,552	(31)%
Total Production (Boe/d) @ 6:1	29,353	52,326	(44)%
Average Prices			
Natural gas (pre-hedge) ($/Mcf)	5.14	4.54	13%
Natural gas ($/Mcf)	5.39	4.60	17%
Crude oil and liquids (pre-hedge) ($/Bbl)	36.02	36.03	-
Crude oil and liquids ($/Bbl)	32.89	35.27	(7)%
Reserves (proved and probable)			
Natural gas (Bcf)			

Crude oil and liquids (MBbl)			
Estimated present value before tax (discounted @10% using forecast prices and costs)			
Proved ($ millions)			
Proved and probable ($ millions)			
Land (thousands of acres)			
Total net land holdings			
Net undeveloped land holdings			
Drilling Activity (gross)			
Gas	58	10	480%
Oil	4	4	-
Other	-	(1)	-
D&A	5	2	150%
Total wells	67	15	347%
Success rate	93%	87%	7%

	Year Ended December 31, 2003	2002	% Change
FINANCIAL			
Gross Revenue	381,847	473,942	(19)%
Cash Flow			
From operations	167,276	259,916	(36)%
Per share - basic	2.78	4.37	(36)%
- diluted	2.77	4.36	(36)%
Earnings			
Net earnings	2,633	10,307	(74)%
Per share - basic	0.04	0.17	(76)%
- diluted	0.04	0.16	(75)%
Capital expenditures			
Exploration and development	223,753	217,196	3%
Summit acquisition	-	251,422	-
Acquisitions, dispositions and other	(368,731)	25,917	-
Net capital expenditures	(144,978)	494,535	-
Total assets	1,147,848	1,526,786	(25)%
Net debt	307,704	555,243	(45)%
Shareholders' equity	501,642	546,105	(8)%
Weighted average common shares outstanding (thousands)	60,098	59,458	
Common shares outstanding at year end (thousands)	60,095	59,459	
Common shares outstanding at March 12, 2004 (thousands)	59,393		
OPERATING			
Production			
Natural gas (MMcf/d)	153	241	(37)%
Crude oil and liquids (Bbl/d)	7,169	5,663	27%
Total Production (Boe/d) @ 6:1	32,630	45,898	(29)%
Average Prices			
Natural gas (pre-hedge) ($/Mcf)	5.99	3.53	70%
Natural gas ($/Mcf)	5.16	4.08	26%
Crude oil and liquids (pre-hedge) ($/Bbl)	38.27	35.20	9%
Crude oil and liquids ($/Bbl)	35.50	34.64	2%
Reserves (proved and probable)			
Natural gas (Bcf)	329.4	618.6	(47)%
Crude oil and liquids (MBbl)	12,513	22,846	(45)%
Estimated present value before tax (discounted @10% using forecast prices and costs)			

Proved ($ millions)	597	983	(39)%
Proved and probable ($ millions)	734	1,258	(42)%

Land (thousands of acres)			
Total net land holdings	3,386	5,077	(33)%
Net undeveloped land holdings	2,800	3,545	(21)%

Drilling Activity (gross)			
Gas	180	114	58%
Oil	16	9	78%
Other	-	1	-
D&A	15	11	36%
Total wells	211	135	56%
Success rate	93%	92%	1%

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Significant Events

- Creation of Paramount Energy Trust (the "Trust")

Paramount created the Trust and dividended the Trust units to the Company's shareholders. The Company transferred effectively all of its producing assets in Northeast Alberta to the Trust providing shareholders with an income-generating investment, in addition to an ongoing growth-focused exploration and production company, Paramount Resources Ltd.

- Non-Core Disposition Program

Through the first half of 2003, Paramount executed a non-core disposition program comprised of many of the smaller properties which were part of the Summit Resources Limited ("Summit") acquisition. This program generated proceeds of $71 million which were used to reduce the Company's debt.

- Disposition of the Sturgeon Lake property

On October 1, 2003, Paramount sold its interest in the Sturgeon Lake property for total consideration of $54.0 million, resulting in a $18.7 million pretax gain. Production from the Sturgeon Lake assets averaged 1,640 Bbl/d of oil and natural gas liquids and 3.0 MMcf/d of natural gas for the nine months ended September 30, 2003.

- Issuance of US$175 million of medium-term senior notes

On October 27, 2003, the Company issued US$175 million senior unsecured notes that bear interest at 7 7/8 percent and mature on October 27, 2010. The notes diversified Paramount's sources of financing and expanded its financial flexibility.

- Discovery of Nogha Pool at Colville Lake

Two discovery wells, Nogha C-49 and M-17, were drilled during the winter of 2003. Based on the success of this drilling, Paramount has drilled three additional wells in the Colville Lake area in the winter of 2004 and is evaluating options for bringing these reserves into production.

Financial

Natural gas production volumes averaged 153 MMcf/d in 2003, a 37 percent decrease from the 241 MMcf/d produced in 2002, primarily as a result of the disposition of Northeast Alberta assets to the Trust (the "Trust assets") in the first quarter of 2003, as well as other property dispositions during the year. Production from the Trust assets averaged 97 MMcf/d in 2002. Stronger natural gas demand resulted in a 70 percent increase in Paramount's average natural gas sales price before hedging to $5.99/Mcf as compared to $3.53/Mcf in 2002. Higher natural gas prices were offset by

$53 million of commodity hedging losses incurred during 2003, attributed primarily to natural gas hedges. Paramount's average natural gas price after hedging was $5.16/Mcf as compared to $4.08/Mcf in 2002.

Oil and natural gas liquids ("NGLs") prices before hedging averaged $38.27/Bbl in 2003, as compared to $35.20/Bbl in 2002. Oil and NGLs production increased 27 percent to average 7,169 Bbl/d in 2003 from 5,663 Bbl/d in 2002. This increase is attributable to a full year of production from the assets obtained through the acquisition of Summit.

Paramount's 2003 production profile continues to be significantly weighted to natural gas, despite the acquisition of Summit in 2002. Summit production was approximately 60 percent gas and 40 percent oil and NGLs at the time of acquisition. In 2003 natural gas production contributed 78 percent of Paramount's total production compared to 88 percent in 2002. With the disposition of the Sturgeon Lake property in the fourth quarter of 2003, the Company expects 2004 production to continue to be strongly weighted toward natural gas.

Natural gas production volumes averaged 141 MMcf/d during the fourth quarter, a decrease of 46 percent from 263 MMcf/d for the comparable quarter in 2002. The lower natural gas production is a result of the disposition of the Trust assets, the completion of a successful disposition program of non-core, non-operated natural gas properties, and the sale of the Sturgeon Lake area. Oil and NGLs sales averaged 5,877 Bbl/d in the fourth quarter of 2003 as compared to 8,552 Bbl/d for the comparable quarter in 2002 primarily due to the sale of Sturgeon Lake and other minor oil properties in the current year.

Paramount's cash flow from operations decreased 36 percent to $167.3 million from $259.9 million in 2002. Lower cash flows were primarily a result of $53 million in commodity hedging losses in 2003 as opposed to $47 million in commodity hedging gains in 2002, partially offset by a $50 million increase in petroleum and natural gas revenues due to higher commodity prices. A $40 million gain on sale of the investment in Peyto Exploration was also included in 2002 cash flows.

Fourth-quarter cash flow totalled $43.2 million, a decrease of 30 percent from $62.1 million during the same period in 2002. The decrease in cash flow is a result of lower production levels as compared to the fourth quarter of 2002.

The Company recorded net earnings of $2.6 million, as compared to net earnings of $10.3 million in 2002. The lower earnings in 2003 are primarily due to lower cash flows as well the inclusion of $37 million Surmont compensation in 2002 net earnings.

Core Producing Areas

Kaybob

Paramount participated in 43 (20.8 net) wells in the fourth quarter bringing the 2003 total to 74 (43.9 net) wells for the year, resulting in 64 (35.9 net) gas wells, 8 (8.0 net) oil wells and 2 (0 net) dry holes. This activity level is up 100 percent from 2002, when Paramount participated in the drilling of 37 (29.76 net) wells at Kaybob. Total capital expenditures in the Kaybob area in 2003, including facility additions and optimization projects, were $65 million, up from approximately $45 million in 2002.

Gas production in the Kaybob Core Area averaged 79.5 MMcf/d, and oil and natural gas liquids production averaged 2,451 Bbl/d for 2003. Production declines in the first half of the year were a reflection of the limited capital spending in the latter part of 2002 and in the first half of 2003 ($21 million) as cash flow was directed to debt reduction. The increase in third and fourth quarter spending ($44 million) resulted in the production increases in the fourth quarter of 2003 and first quarter of 2004. Year-end exit rates for Kaybob were 90 MMcf/d and 2,400 Bbl/d; production rates are expected to increase further in 2004 to 97 MMcf/d and 2,590 Bbl/d for the year.

Paramount continued to take advantage of its existing production and land base in the Kaybob area by exploiting new reserves in existing fields. Most activity through the second half of 2003 and all of 2004 will be concentrated on the execution of the downspacing program. Most of the wells drilled in this area are within easy access to existing pipelines and gas plants, thereby reducing finding and development costs. Proved plus probable reserve additions in the Kaybob Core Area under NI 51-101 guidelines were 35.4 Bcf and 834 MBbl (6.73 MMBoe), more than replacing 2003 production of 29 Bcf and 895 MBbl (5.74 MMBoe). Costs of finding and development for the proved plus probable reserve additions for the Kaybob area were $9.66/Boe in 2003.

Paramount will continue to increase control of its production by operating wells and production facilities that process the natural gas and liquids. There are currently four Company-operated gas plants in the area that process 64 percent of Paramount's natural gas production. Operations are underway to consolidate two of the Paramount operated gas plants, which should reduce operating costs without sacrificing any processing capacity. The Kaybob North oil battery was completed in 2003; this facility will reduce operating and processing costs related to oil and condensate in the Kaybob area. Plans are currently being evaluated to use this new battery as a heavy oil blending facility, which would generate additional revenue for Paramount. Regulatory approvals are being sought to expand the Kaybob North oil battery to include water disposal, which will further lower operating costs. Additional inlet compression was installed at the Clover plant, adding 5 MMcf/d of additional processing capacity to the plant. Sour gas field compression was added in the Pine Creek area to allow for the production of currently shut-in sour gas.

Grande Prairie

This operating area was previously described as the Sturgeon Lake Core Area. Assets related to Sturgeon Lake were sold on October 1, 2003 for $54.0 million. This was a high operating cost, very mature property with proved reserves of 2.7 MMBbl of liquids and 4.2 Bcf gas. Paramount originally purchased the Sturgeon Lake asset in two transactions for approximately $34 million during 2001 and 2002 and estimates that it has recovered virtually all of this in cash flow from the asset. The subsequent sale for $54 million represents an excellent return to Paramount on this investment.

For 2003, production averaged 12.4 MMcf/d and 1,767 Bbl/d of liquids. Despite the sale of Sturgeon Lake which reduced production by 3.0 MMcf/d and 1,640 Bbl/d of liquids, the exit rates were 22.4 MMcf/d and 772 Bbl/d. Production rates for gas increased because of the successful capital program, primarily in the Mirage and Saddle Hills fields. In 2003 Paramount drilled 45 gross wells (29.9 net) in the Grande Prairie Core Area. Also in 2003, infrastructure and limited production was added in the Goose, Shadow and Valhalla fields that Paramount plans to exploit with the 2004 capital program.

In Mirage, 17.3 net wells were drilled on this new Dunvegan play. At the end of the year 7.6 MMcf/d was on production from 7.4 net wells with an additional 1.6 wells to be tied in, 0.3 wells to complete and the balance being evaluated. Up to 40 wells are planned in 2004 to follow up and expand upon this play. The successful Saddle Hills Wabamun well was producing at 9 MMcf/d at year-end. Paramount plans to follow up with up to six more similar deep wells in 2004.

In 2004 the new Berry Lake field in Northeast Alberta came onstream March at 5 MMcf/d net to Paramount. Production rates may increase if capacity in the third-party gas plant is available.

Northwest Alberta

The Northwest Alberta Core Area covers the extreme northwest corner of Alberta, extending into the Cameron Hills in the Northwest Territories. Two significant events for Northwest Alberta Core Area in 2003 were the completion of the Cameron Hills oil gathering system, battery, and liquid transportation line situated between the Paramount operated Bistcho Lake facility and the Zama terminal, and the discovery and tie-in of Pekisko gas at Haro.

Paramount participated in the drilling of 23 wells (21.2 net) in the Northwest Alberta area during the 2003 calendar year. The vast majority of field activities relating to seismic acquisition, drilling, and construction occurred in the first quarter due to restricted seasonal access of the area. Annualized 2003 net average production for the region is as follows: natural gas sales 22.3 MMcf/d, crude oil and natural gas liquids 448 Bbl/d. Divestiture of the Pedigree and West Negus properties reduced annual gas production for the region by approximately 5 MMcf/d. An oil gathering line failure in conjunction with a wax blockage in another pipeline resulted in Paramount realizing only about half of the crude oil production capability of Cameron Hills in 2003.

Focus of activity for the Northwest Alberta group in 2004 will be at the Cameron Hills and Haro properties, with virtually all occurring in the first quarter due to the winter-only access nature of the area. Paramount will participate at Haro in the drilling of 12 gas wells (7.5 net), expansion of the existing gas handling capacity from 6 MMcf/d (1.4 MMcf/d net) to 12 MMcf/d (5.9 MMcf/d net). The Cameron Hills oil project is being expanded with the addition of 4 oil wells (3.5 net) and the facilities necessary to bring those wells on production in 2004. One net gas well will also be drilled at Cameron Hills in the first quarter. The total number of wells in which Paramount will be participating in the Northwest Alberta Core Area in 2004 is expected to be 23 (15.5 net).

Liard Basin - Northeast British Columbia / Northwest Territories

Production from this operating unit averaged 11.6 MMcf/d in 2003. At Maxhamish, the b-83-K/94-O-14 well was tied in and existing producing wells were worked over to maximize performance. At the Chevron-operated Liard pool, the 2K-29 location was drilled, completed and placed on production in early May. At Clarke Lake, two locations were drilled with one well at b-57-I/94-J-10 tied in during December.

Exploration activity was dominated by nine locations farmed out to Anadarko at Liard and Arrowhead, NWT. The multi-well program included the drilling of seven Devonian and two Chinkeh locations during the winter of 2003. Two of the Devonian locations did not reach total depth and will finish drilling in 2004. Hydrocarbons discovered as a result of this program have allowed Anadarko to apply to the NEB for six significant discovery licenses to hold expiring lands. Paramount also drilled one unsuccessful Mattson test at K-36 located northeast of Fort Liard.

Looking forward to 2004, development activity will include further drilling at Chevron Liard and at Clarke Lake as well as recompletion work at Liard/Maxhamish. Exploration will expand into other areas of Northeast British Columbia with the drilling of various Cretaceous and Triassic plays as well as deeper Mississippian and Devonian prospects.

Southern

The Southern Core Area is the most geographically extensive unit of Paramount Resources, with oil and gas producing in southern Alberta, Saskatchewan, Montana and North Dakota. The Southern Core Area completed the consolidation and focus process in late 2003. This process has seen the area divest of smaller interest and non-operated/non-core properties to pursue the growth of fewer, higher interest core properties. The average production for the year was 9.5 MMcf/d of gas, with 2,457 Bbl/d of oil and NGLs, totalling 4,048 Boe/d. At the end of the year, the Southern area was producing 9.8 MMcf/d of gas, with 2,018 Bbl/d of oil and NGLs, giving a total rate of 3,643 Boe/d.

The main activities for 2003 centered in the Chain/Craigmyle area, where 7 wells were drilled, 15 recompletions were performed, several compressors were modified and one added, resulting in a 30 percent increase in production for the area. This area will also be the focus of activities for the coming year with 17 shallow gas wells planned, and continued modifications to the production systems.

New and reactivated production was also added in Alder Flats (56 percent increase), Enchant (5 percent increase), and Long Coulee (100 percent increase). Late in 2003, two new wells were added at Retlaw, which will result in production increases in the coming year. Enchant, Long Coulee, Sylvan Lake and Retlaw will also see further development in 2004. At Paramount-operated oil pools in Rabbit Hills, Montana, and Lougheed, Saskatchewan, new or enhanced waterfloods resulted in production increases of up to 20 percent. Further work is planned in both the Southeast Saskatchewan and North Dakota oil properties in 2004.

Long Term Projects

Paramount has continued to advance its long-term projects at Colville Lake in the Central Mackenzie Valley of the Northwest Territories. At Colville Lake, two successful gas wells were drilled and tested on the Nogha structure in 2003 with results that exceeded the Company's expectations. A further well was drilled on the Nogha prospect during the 2004 winter that has been successfully drilled and cased. Two additional prospects were tested during the 2004 winter drilling season with one exploration well further north at Manoir Ridge and one exploration well further west at West Nogha; both were successfully drilled and cased as potential gas wells. At the time of writing, all of the wells drilled during the winter of 2004 are undergoing completion operations. Success to date from exploration drilling at Colville Lake is now leading to the evaluation of several development scenarios including participation in the Mackenzie Valley Pipeline or possibly the construction of a 500-mile long dedicated pipeline from Norman Wells south into Alberta to tie in to the existing pipeline infrastructure.

Another new project for Paramount will be to test the feasibility and potential bitumen reserves of its SAG-D projects in Northeast Alberta. The Company executed its first drilling program to commence the delineation of our bitumen prospects in northeast Alberta. A total of 12 wells were drilled in the 2004 winter program to delineate the bitumen reserves: 7 wells were drilled at the Leismer prospect and 5 wells at the Company's Surmont prospect.

Reserves

Paramount's reserves for the year ended December 31, 2003, were evaluated by McDaniel and Associates ("McDaniel") who has evaluated Paramount's reserves for the entire 25-year existence of the Company. Commencing with the most recent year ended December 31, 2003, Paramount's reserves have been calculated in compliance with the new National Instrument 51-101. The new reserve disclosure standards related to NI 51-101 require a higher standard of confidence in reserve volumes within the individual reserve reporting categories. In particular, proved reserves are now defined as having a 90 percent probability that these reserves will be recovered and probable reserves are now defined as having at a 50 percent probability that these reserves will be recovered. Paramount estimates that the effects of the proved reserves revisions associated with NI 51-101 to be 5 percent of total proved reserves at the beginning of the year, excluding the Trust.

The following table summarizes the reserves evaluated as at December 31, 2003, using McDaniel's forecast prices and cost.

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Proved and Probable Reserves

Reserve Category	Natural Gas (Bcf)	Light and Medium Crude Oil (MBbl)	Natural Gas Liquids (MBbl)	Boe (MBoe)
Canada				
Proved				
Developed Producing	174.9	3,755	3,269	36,174
Developed Non-Producing	47.6	529	543	9,004
Undeveloped	18.6	437	111	3,648
Total Proved	241.1	4,721	3,923	48,827
Probable	87.7	1,271	479	16,367
Total Proved Plus Probable Canada	328.8	5,992	4,402	65,194
United States				
Proved				
Developed Producing	0.5	1,971	2	2,056
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	0.5	1,971	2	2,056
Probable	0.1	143	3	163
Total Proved Plus Probable US	0.6	2,114	5	2,219
Total Company				
Total Proved	241.7	6,692	3,925	50,883
Total Probable	87.7	1,414	482	16,530
Total Reserves	329.4	8,106	4,407	67,413

Before Tax Net Present Value
($ millions)

Reserve Category	Discount Rate 0%	5%	10%
Canada			
Proved			
Developed Producing	636.9	545.8	483.0
Developed Non-Producing	140.1	101.7	79.9
Undeveloped	59.2	34.7	22.6
Total Proved	836.2	682.2	585.5
Probable	267.9	184.9	135.2
Total Proved Plus Probable Canada	1,104.1	867.1	720.7
United States			
Proved			
Developed Producing	15.7	13.7	12.2

Developed Non-Producing	(0.3)	(0.3)	(0.3)
Undeveloped	-	-	-
Total Proved	15.4	13.4	11.9
Probable	1.6	1.3	1.0
Total Proved Plus Probable US	17.0	14.7	12.9
Total Company			
Total Proved	851.6	695.6	597.4
Total Probable	269.5	186.2	136.2
Total Reserves	1,121.1	881.8	733.6

(Columns may not add due to rounding)

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Reserve Reconciliation for Year-end 2003

Paramount's reserves reflected the dispositions of virtually all of Paramount's assets in northeast Alberta to the Trust, the Sturgeon Lake assets and additional minor non-core assets, all of which occurred during 2003. As well, Paramount's reserve disclosure for the year ended 2003 is now evaluated using the newly implemented standards of disclosure defined by NI 51-101. Total proved reserves at year end 2003 stood approximately 242 Bcf and 10.6 MMBbl or 51 MMBoe and proved plus probable reserves were 329 Bcf and 12.5 MMBbl or 67.4 MMBoe.

The following table sets forth the reconciliation of Paramount's gross reserves for the year ended December 31, 2003, as evaluated by McDaniel using forecast prices. We have reconciled our reserves to January 1, 2003, proved plus 50 percent of probable reserves (Established reserves). Gross reserves include working interest reserves before royalties.

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Reserves (Company share before royalty)

	Proved Reserves			Probable Reserves		
	Gas Bcf	Oil & NGL MBbl	Boe MBoe	Gas Bcf	Oil & NGL MBbl	Boe MBoe
Paramount Resources Ltd. January 1, 2003 (excl Trust)	282.3	17,545	64,595	66.4	2,650	13,717
Paramount Energy Trust, Jan. 1, 2003	164.3	-	27,367	19.7	-	3,283
Total Reserves Jan 1, 2003(1)	446.5	17,545	91,961	86.1	2,650	17,000
Divestments						
Paramount Energy Trust	158.4	-	26,400	19.7	-	3,283
Sturgeon Lake	3.4	2,147	2,714	0.6	347	447
Minor Divestments	12.8	2,462	4,595	2.0	225	558
Total 2003 Divestments(2)	(174.6)	(4,609)	(33,709)	(22.3)	(572)	(4,288)
Total 2003 Acquisitions	1.6	-	267	0.1	-	17
2003 Capital Program Additions	52.3	1,428	10,145	11.2	251	2,118
Total 2003 Production	(55.8)	(2,617)	(11,917)	-	-	-
Technical Revisions(3)	(10.4)	(937)	(2,670)	12.6	(433)	1,667
Revisions due to NI 51-101(4)	(17.9)	(193)	(3,176)	-	-	-

Total Revisions	(28.3)	(1,130)	(5,847)	12.6	(433)	1,667
Total Reserves Jan. 1, 2004	241.7	10,617	50,900	87.7	1,896	16,513

Reserves (Company share before royalty)

Proved + Probable Reserves

	Gas Bcf	Oil & NGL MBbl	Boe MBoe
Paramount Resources Ltd. January 1, 2003 (excl Trust)	348.7	20,195	78,312
Paramount Energy Trust, Jan. 1, 2003	183.9	-	30,650
Total Reserves Jan 1, 2003(1)	532.6	20,195	108,962
Divestments			
Paramount Energy Trust	178.1	-	29,683
Sturgeon Lake	4.0	2,494	3,161
Minor Divestments	14.8	2,687	5,153
Total 2003 Divestments(2)	(196.9)	(5,181)	(37,997)
Total 2003 Acquisitions	1.7	-	284
2003 Capital Program Additions	63.5	1,679	12,263
Total 2003 Production	(55.8)	(2,617)	(11,917)
Technical Revisions(3)	2.2	(1,370)	(1,003)
Revisions due to NI 51-101(4)	(17.9)	(193)	(3,176)
Total Revisions	(15.7)	(1,563)	(4,180)
Total Reserves Jan. 1, 2004	329.4	12,513	67,413

(Columns may not add due to rounding)
(1) January 1, 2003 reserves are proved plus half probable
(2) Total 2003 divestitures net of reported production in 2003
(3) Paramount estimates of conventional technical revisions
(4) Paramount estimates of revisions due to NI 51-101

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Finding and Development Costs

Paramount has calculated the capital associated with the 2003 reserve additions and as such has excluded two separate expenditures. The first is the $23.3 million of expenditure associated with properties which were disposed during the year. Capital expenditures in this category were almost entirely related to the Ells property and the Sturgeon Lake property, which were both sold during the year. The other capital excluded from the finding and development cost calculation was the $5.8 million associated with the exploration at Colville Lake. This capital will be included in the finding and development calculation during the year in which reserves are first booked for Colville Lake by the Company. In addition, capital was reduced by $5.0 million to reflect the net increase in the value of our undeveloped acreage inventory. Future capital of $2.4 million to fully develop the booked proved reserves, and $3.3 million to fully develop the booked proved and probable reserves, were included in the finding and development calculation. Paramount's finding and development costs for new reserve additions were calculated to be $18.93/Boe for proved reserves and $15.73/Boe for proved plus probable reserves. Finding and development costs at Kaybob in 2003 of $9.66/Boe were in line with expectations. Paramount has allocated approximately 50 percent of its 2004 capital budget to a continuation of the downspacing program in the Kaybob area and will positively influence Paramount's 2004 finding and development costs.

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	Proved Capital ($MM)	Proved Reserves MBoe	Proved + Proved F&D $/Boe	Proved + Probable Capital ($MM)	Proved + Probable Reserves Mboe	Probable F&D $/Boe
Finding and Development Costs						
Extensions and discoveries	$192.0	10,145	$18.93	$192.9	12,262	$15.73

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Outlook

Paramount has budgeted a total of $240 million for capital expenditures for 2004 with the expectation that this will allow us to increase production from Q3 2003 exit levels of 130 MMcf/d and 6,000 Bbl/d (28,000 Boe/d) to average 160 MMcf/d and 6,000 Bbl/d (32,500 Boe/d) in 2004 with an anticipated 2004 exit rate higher than the annual average. Cash flow in 2004 is forecast to be about $240 million or approximately $4.00/share, which is essentially equal to the capital expenditure budget. New short-term additions in production will be principally in the Kaybob and Grande Prairie core areas. The Kaybob downspacing program will continue with $100 million budgeted to drill 70 wells throughout 2004. Grande Prairie has a budget of $50 million to drill 65 wells predominantly targeting the repetition of the successful shallow Dunvegan gas play as well as six new deep Wabamun prospects that have been identified. The capital activity at the Liard, Southern, and Northwest Core Areas is expected to be sufficient to replace declines through the year. With visible short-term growth, principally at Kaybob and Grande Prairie, combined with an exciting portfolio of long-term prospects, Paramount considers its value creation potential for shareholders to be unparalleled.

Advisory Regarding Reserves Data and Other Oil and Gas Information

In this news release, certain natural gas volumes have been converted to Boe on the basis of six thousand cubic feet (Mcf) to one barrel (Bbl). Boe may be misleading, particularly if used in isolation. A Boe conversion ration of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and doers not represent equivalency at the well head.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Advisory Regarding Forward-Looking Statements

This news release contains forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. The forward-looking statements in this news release include statements with respect to future production, capital expenditures, drilling, operating costs, cash flow, and the magnitude of oil and natural gas reserves. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on them because we can give no assurance that such expectations will prove to have been correct. Factors that could cause actual results to differ materially from those set forward in the forward looking statements include general economic business and market conditions, fluctuations in interest rates, production estimates, our future costs, future crude oil and natural gas prices, and our reserve estimates. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. We undertake no obligation to update our forward-looking statements except as required by law.

A conference call will be held with the senior management of Paramount Resources Ltd. to answer questions with respect to the year-end results at 9:00 a.m. MST on Thursday, March 25, 2004. To participate please call 1- 877-211-7911 or 1-416-405-9310 approximately 15 minutes before the call is to begin.

The conference call will be live webcast from www.paramountres.com or www.companyboardroom.com.

A replay of the conference call will be available within an hour of the call for seven days: until April 1, 2004. The number for the replay is 1-800-408-3053 or 1-416-695-5800 with passcode number 3027074.

The conference call will be available for replay on the Company website, www.paramountres.com within two hours of the webcast.

Paramount is a Canadian oil and natural gas exploration, development and production company with operations focused in Western Canada. Paramount's common shares are listed on the Toronto Stock Exchange under the symbol "POU".

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD & A")

Paramount Resources Ltd. ("Paramount" or the "Company") is pleased to report its financial and operating results for the year ended December 31, 2003.

The following discussion of financial position and results of operations should be read in conjunction with the consolidated financial statements and related notes for the year ended December 31, 2003. The consolidated financial statements have been prepared in Canadian dollars and in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to United States GAAP is included in Note 18 to the consolidated financial statements.

This MD&A contains forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. The forward-looking statements in this MD&A include statements with respect to, among other things: Paramount's business strategy, Paramount's intent to control marketing and transportation activities, the weighting of Paramount's production toward natural gas, reserve estimates, production estimates, hedging policies, site restoration costs, the size of available income tax pools, the renewal of the Company's credit facility, the funding sources for the Company's capital expenditure program, cash flow estimates, environmental risks faced by the Company and compliance with environmental regulations, commodity prices, and the impact of the adoption of various Canadian Institute of Chartered Accountants Handbook Sections and Accounting Guidelines.

Although Paramount believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on them because the Company can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward-looking statements not to be correct, including known and unknown risks and uncertainties inherent in the Company's business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate and interest rate fluctuations, availability of services and supplies, market competition, uncertainties in the estimates of reserves, the timing of development expenditures, production levels and the timing of achieving such levels, the Company's ability to replace and expand oil and gas reserves, the sources and adequacy of funding for capital investments, future growth prospects and current and expected financial requirements of the Company, the cost of future dismantlement and site restoration, the Company's ability to enter into or renew leases, the Company's ability to secure adequate product transportation, changes in environmental and other regulations, the Company's ability to extend its debt on an ongoing basis, and general economic conditions. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. We undertake no obligation to update our forward-looking statements except as required by law.

In this MD&A, certain natural gas volumes have been converted to barrels of oil equivalent (Boe) on the basis of six thousand cubic feet (Mcf) to one barrel (Bbl). Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf=1 Bbl is based on an energy equivalency conversion method, primarily applicable at the burner tip and does not represent equivalency at the well head.

The date of this MD&A is March 12, 2004.

Additional information on the Company, including the Annual Information Form, can be found on the SEDAR website at www.sedar.com.

Paramount is an exploration, development and production company with established operations in Alberta, British Columbia, Saskatchewan, the Northwest Territories, Montana, North Dakota and California. Management's strategy is to maintain a balanced portfolio of opportunities, to grow reserves and production in the Company's core areas while maintaining a large inventory of undeveloped acreage, to focus on natural gas as a commodity, and to selectively enter into joint venture agreements for high risk/high return prospects.

SIGNIFICANT EVENTS

- Creation of Paramount Energy Trust (the "Trust")

In 2002, the Company announced its intention to create an independent energy trust, providing shareholders with an investment which would complement Paramount's historical exploration and development strategy.

1. On February 3, 2003, Paramount transferred to the Trust assets in the Legend area of Northeast Alberta for net proceeds of $28 million, which was paid to Paramount on March 11, 2003, and 9,907,767 units of the Trust.

2. On February 3, 2003, Paramount declared a dividend-in-kind of an aggregate of 9,907,767 units of the Trust. The dividend was paid to holders of Paramount common shares of record on the close of business on February 11, 2003. The dividend was declared after the Trust received all regulatory clearances with respect to its final prospectus in Canada and its registration statement in the United States. The final prospectus and registration statement qualified and registered (i) the dividend trust units, (ii) rights to purchase further trust units, which rights were issued to unitholders after the payment of the dividend, and (iii) the trust units issuable upon the exercise of the rights.

3. On March 11, 2003, in conjunction with the closing of a rights offering by the Trust, Paramount disposed of additional assets in Northeast Alberta to Paramount Operating Trust for consideration of $167 million, including adjustments to the purchase price. The combined production of natural gas including the assets in the Legend area averaged 97 MMcf/d during 2002.

The closing of the above transactions in the first quarter of 2003 represent the completion of the formation and structuring of Paramount Energy Trust.

- Disposition of the Sturgeon Lake property

On October 1, 2003, Paramount sold its interest in the Sturgeon Lake property, including the associated oil batteries and gas plants, for total consideration of $54.0 million. Production from the Sturgeon Lake assets averaged 1,640 Bbl/d of oil and natural gas liquids and 2,965 Mcf/d of natural gas for the nine months ended September 30, 2003. A pre-tax gain on sale of property and equipment of $18.7 million was recorded on the disposition.

- Issuance of US$175 million of medium-term senior notes

On October 27, 2003, the Company closed an offering of US$175 million in senior unsecured notes. The notes bear interest at 7 7/8 percent, and mature on October 27, 2010. The offering allowed Paramount to diversify its sources of financing and expand its financial flexibility.

- Sale of non-core properties

During 2003, the Company successfully executed a disposition program consisting of minor, non-core producing and non-producing properties for total consideration of $71.2 million.

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REVENUE & PRODUCTION

Revenue (thousands of dollars)	2003	2002	2001
Natural gas	$ 333,924	$ 311,438	$ 481,436
Oil and natural gas liquids	100,135	72,750	28,442
Petroleum and natural gas revenue	434,059	384,188	509,878
Commodity hedging gain (loss)	(53,204)	46,813	15,808
Gain (loss) on investments	(1,020)	40,830	2,982
Other	2,012	2,111	(295)
Gross revenue	$ 381,847	$ 473,942	$ 528,373

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Petroleum and natural gas revenue totaled $434.1 million in 2003, as compared to $384.2 million in 2002 (2001 - $509.9 million). The increase in revenue is due to higher commodity prices, mitigated partially by lower natural gas production volumes as compared to the prior year. Natural gas production volumes averaged 153 MMcf/d in 2003, a 37 percent decrease from the 241 MMcf/d produced in 2002 (2001 - 225 MMcf/d), primarily as a result of the disposition of Northeast Alberta assets to the Trust (the "Trust assets") in the first quarter of 2003, as well as other property dispositions closed during the year. Production from the Trust assets averaged 97 MMcf/d in 2002. Stronger natural gas demand resulted in an increase of 70 percent in Paramount's average natural gas sales price before hedging to $5.99/Mcf as compared to $3.53/Mcf in 2002 (2001 - $5.93/Mcf). Paramount's average natural gas price after hedging was $5.16/Mcf as compared to $4.08/Mcf in 2002 (2001 - $6.12/Mcf).

Oil and natural gas liquids ("NGL") prices before hedging averaged $38.27/Bbl in 2003, as compared to $35.20/Bbl in 2002 (2001 - $35.48/Bbl). Oil and NGL production increased 27 percent to average 7,169 Bbl/d in 2003 as compared to 5,663 Bbl/d in 2002 (2001 - 2,165 Bbl/d). This increase is attributable to the inclusion in 2003 results of a full year of production from the assets obtained through the acquisition of Summit Resources Limited ("Summit").

Paramount's 2003 production profile continues to be significantly weighted to natural gas, despite the acquisition of Summit in 2002. Summit production was approximately 60 percent natural gas and 40 percent oil and NGL at the time of acquisition. In 2003 natural gas production contributed 78 percent of Paramount's total production compared to 88 percent in 2002 (2001 - 95 percent). With the disposition of the Sturgeon Lake property in the fourth quarter of 2003, the Company expects 2004 production to continue to be strongly weighted towards natural gas.

Fourth quarter petroleum and natural gas revenue before hedging totaled $86.1 million as compared to $135.0 million for the comparable quarter in 2002 (2001 - $65.1 million). The decrease in revenue is due to lower production volumes, mitigated partially by higher commodity prices before hedging. Natural gas production volumes averaged 141 MMcf/d during the fourth quarter, a decrease of 46 percent as compared to 263 MMcf/d for the comparable quarter in 2002 (2001 - 218 MMcf/d). Lower natural gas production is a result of the disposition of the Trust assets, the completion of a successful disposition program of non-core, non-operated natural gas properties, and lower production levels in the Kaybob area in comparison to the fourth quarter of 2002. Oil and NGL sales averaged 5,877 Bbl/d in the fourth quarter of 2003 as compared to 8,552 Bbl/d for the comparable quarter in 2002 (2001 - 2,002 Bbl/d). Decreased oil and NGL production is primarily due to the sale of Sturgeon Lake and other minor oil properties in the current year, partially offset by new oil production at Cameron Hills.

The Alberta Securities Commission released National Instrument 51-101 (the "Instrument") in 2003, with an effective date of September 30, 2003. The Instrument requires all reported petroleum and natural gas production to be measured in marketable quantities, with adjustments for heat content included in the commodity price reported. The Company has adopted the Instrument prospectively. As such, fourth quarter natural gas production volumes are measured in marketable quantities, with adjustments for heat content and transportation reflected in the reported natural gas price.

Paramount's financial success is contingent upon the growth of reserves and production volumes and the economic environment that creates a demand for natural gas and crude oil. Such growth is a function of the amount of cash flow that can be generated and reinvested into a successful capital expenditure program. To protect cash flow against commodity price volatility, the Company will, from time to time, manage cash flow by utilizing commodity price hedges. The hedging program is generally for periods of less than one year and would not exceed 50 percent of Paramount's current production volumes.

At December 31, 2003, Paramount had the following commodity price hedges in place:

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AECO	Price	Term
10,000 GJ/d	$7.35	January 2004 - March 2004

10,000 GJ/d	$6.26	January 2004 - March 2004
10,000 GJ/d	$6.14	January 2004 - March 2004
20,000 GJ/d	$6.51	January 2004 - March 2004
10,000 GJ/d	$5.55	April 2004 - October 2004
10,000 GJ/d	$5.51	April 2004 - October 2004
WTI		
1,000 Bbl/d	US$24.07	May 2002 - April 2004
1,000 Bbl/d	US$25.00 - $30.25 collar	January 2004 - December 2004

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Had these financial contracts been settled on December 31, 2003, using prices in effect at that time, the mark to market before tax loss would have totaled $1.6 million.

Subsequent to year end, the Company entered into the following hedging arrangements:

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AECO	Price	Term
20,000 GJ/d	$5.80	April 2004 - October 2004
10,000 GJ/d	$5.81	April 2004 - October 2004
10,000 GJ/d	$5.86	April 2004 - October 2004
10,000 GJ/d	$5.25 - $6.80 collar	April 2004 - October 2004
10,000 GJ/d	$5.25 - $6.75 collar	April 2004 - October 2004

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Commodity hedging gains and losses are recorded based on monthly cash settlements with counterparties. Where hedging contracts are terminated before the end of the contract, the resulting payment or cash receipt is recorded as deferred revenue or deferred hedging loss on the Company's balance sheet and amortized into income over the initial life of the contract.

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties and controls third party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures.

The Company also has in place foreign exchange hedges, which have fixed the exchange rate on US $24.4 million for CDN $34.9 million over the next two years at CDN $1.4335. For the year ended December 31, 2003, gross revenue included gains from foreign currency hedging activity of $0.5 million (2002 - $3.4 million loss and 2001 - $1.7 million loss). At December 31, 2003, the estimated fair value of these hedges based on the Company's assessment of available market information was $3.3 million.

During 2003, approximately 75 percent of Paramount's natural gas sales were under long-term contracts to gas aggregators and direct-sales purchasers as compared to 43 percent and 42 percent for 2002 and 2001, respectively. The increase in the percentage is due to the lower production volumes as a result of the transfer of the Trust assets in early 2003. Despite transferring approximately 97 MMcf/d of natural gas production to the Trust, Paramount kept the majority of the long-term contracts for natural gas sales.

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NETBACKS

Netbacks ($/Boe)	2003	2002	2001
Gross revenue before hedging	$ 36.53	$ 25.50	$ 35.40
Royalties	6.93	4.44	6.89
Operating costs	6.82	5.14	4.22
Operating netback	22.78	15.92	24.29
Commodity hedging loss (gain)	4.47	(2.79)	(1.09)
General and administrative(1)	1.57	0.95	0.85
Bad debt expense	0.50	-	-
Lease rentals	0.30	0.27	0.30
Interest on long-term debt(2)	1.66	1.43	1.33
Current and Large Corporations tax	0.24	0.55	1.92
Cash flow netback	$ 14.04	$ 15.51	$ 20.98

(1) Net of non-cash general and administrative expenses.
(2) Net of non-cash interest expense.

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GAIN (LOSS) ON SHORT-TERM INVESTMENTS

In 2003 Paramount experienced a loss on short-term investments of $1.0 million, as compared to a gain of $40.8 million in 2002. In the second quarter of 2003, Paramount wrote off its investment in Jurassic Oil and Gas Ltd, a private exploration company based in Calgary. Paramount routinely utilizes a portion of its working capital to make short-term investments in private and publicly traded oil and gas companies. Accordingly, related gains and losses are included in cash flow from operations.

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ROYALTIES

Royalties (thousands of dollars)	2003	2002	2001
Crown royalties	$ 79,496	$ 71,535	$ 94,253
Other royalties	3,516	3,658	5,953
	83,012	75,193	100,206
Alberta Royalty Tax Credit	(500)	(749)	(500)
Net royalties	$ 82,512	$ 74,444	$ 99,706
Average corporate royalty rate as a percentage of petroleum and natural gas revenue before hedging	19.0%	19.4%	19.6%

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For 2003, net royalties increased to $82.5 million from $74.4 million in 2002 (2001 - $99.7 million) due to higher natural gas prices. As a percentage of revenue, Paramount's corporate royalty rate is substantially unchanged from the prior year, at 19.0 percent compared to 19.4 percent in 2002.

Fourth quarter royalties totaled $10.7 million as compared to $28.2 million for the fourth quarter in 2002 (2001 - $12.4 million). The decrease in royalty costs reflects the decrease in production volumes offset partially by higher commodity prices.

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OPERATING EXPENSES

Operating Expenses (thousands of dollars)	2003	2002	2001
Operating expenses	$81,193	$86,067	$61,045
Net operating expenses per Boe	$ 6.82	$ 5.14	$ 4.22

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Paramount's 2003 operating expenses decreased 6 percent to $81.2 million from $86.1 million in 2002 (2001 - $61.0 million). On a units-of-production basis, operating costs increased to $6.82/Boe from $5.14/Boe in 2002 (2001 - $4.22/Boe). The Company experienced a general increase in the costs of goods and services including higher labour and energy costs. These increases, combined with a decrease in production, resulted in the Company having higher than expected unit operating expenses. Paramount constructs and operates plant facilities and gathering systems as a corporate strategy in order to control the flow of its natural gas to market. These facilities incur fixed costs, which are in addition to the costs incurred at the well level, thereby increasing total operating expenses and the relative magnitude of the per unit costs.

Fourth quarter operating costs decreased to $22.3 million as compared to $23.5 million a year earlier, primarily due to the decreased well and production base resulting from the sale of the Trust assets and other assets earlier in 2003. Fourth quarter operating costs increased on a units-of-production basis to $8.25/Boe from $4.88/Boe for the comparable quarter in 2002. The increase in unit operating costs is primarily a result of charges stemming from the settlement of a dispute with a facility operator, as well as post-closing adjustments related to the Sturgeon Lake property sale incurred during the quarter.

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GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses (thousands of dollars)	2003	2002	2001
Gross general and administrative expenses	$ 31,539	$ 30,868	$ 26,374
Operating recoveries	(12,855)	(15,238)	(15,766)
General and administrative expenses before stock-based compensation	18,684	15,630	10,608
Stock-based compensation expenses	1,214	582	1,738
Net general and administrative expenses	$ 19,898	$ 16,212	$ 12,346
Net general and administrative expenses per Boe	$ 1.67	$ 0.97	$ 0.85

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General and administrative expenses, net of operating recoveries and before stock-based compensation expenses, increased to $18.7 million in 2003 as compared to $15.6 million in 2002 (2001 - $10.6 million). General and administrative costs, post-disposition of Trust assets, did not decrease, as Paramount has increased its head office staffing levels in order to enable the Company to identify and develop new core areas and build its production portfolio. This initiative has resulted in Paramount advancing its long-term projects such as Colville Lake, Northeast Alberta bitumen and coal bed methane, and developing successful new fields in existing core areas within Grande Prairie and Northwest Alberta. The Company has also increased administrative staff levels to ensure compliance with new corporate and reporting obligations in Canada and the United States; certain of these are a result of the US debt offering closed in 2003. Operating recoveries are lower in 2003 by comparison to the prior year due to a lower well count and reduced field staff, as a result of the disposition of the Trust assets and other assets in 2003. Paramount does not capitalize any general and administrative expenses.

In 2003, Paramount adopted the new recommendation of the Canadian Institute of Chartered Accountants ("CICA") related to stock-based compensation. The recommendation has been adopted prospectively, with no restatement of prior periods. As a result, the Company recorded a non-cash provision of $1.2 million in the fourth quarter in respect of stock options granted during 2003. Stock-based compensation expenses incurred in prior years were in respect of the Company's Share Appreciation Rights Plan, which was cancelled in February 2003.

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INTEREST EXPENSE

Interest Expense (thousands of dollars)	2003	2002	2001
Interest expense	$ 19,917	$ 23,943	$ 19,291
Total debt, December 31	$298,561	$539,270	$316,600
Average debt outstanding for the period	$340,919	$448,951	$295,456

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Interest expense decreased to $19.9 million in 2003 from $23.9 million in 2002 (2001 - $19.3 million). The decrease reflects lower average debt levels for the Company in 2003 as a result of the disposition of the Trust assets, offset somewhat by the higher cost of borrowing of the US$ notes in the current year.

DRY HOLE COSTS

Under the successful efforts method of accounting, costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. Other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense as incurred. For 2003, dry hole costs amounted to $36.6 million as compared to $120.1 million in 2002 (2001 - $8.9 million). The 2003 provision includes $6.1 million of costs associated with wells drilled in the current year and $30.5 million associated with exploratory wells drilled in Canada and the United States in previous years, which the Company has determined will not be capable of production in economic quantities.

Geological and geophysical expenses decreased during 2003 to $8.5 million from $9.3 million in the previous year (2001 - $10.6 million).

DEPLETION, DEPRECIATION AND AMORTIZATION

The current year provision for depletion and depreciation expense totaled $163.4 million as compared to $169.4 million in 2002 (2001 - $105.4 million). Depletion and depreciation expense includes expired lease costs of $10.2 million. On a units-of-production basis, depletion and depreciation costs averaged $13.72/Boe as compared to $10.11/Boe in 2002 (2001 - $7.28/Boe). Depletion rates in 2003 were affected by the Summit acquisition and the addition of capital costs previously excluded from the depletable base.

Capital costs associated with undeveloped land of $147 million and non-producing petroleum and natural gas properties of $62 million totaling $209 million are excluded from capital costs subject to depletion in 2003 (2002 - $367 million).

FUTURE SITE RESTORATION AND ABANDONMENT COSTS

On an annual basis the Company reviews the liability for future site restoration and abandonment costs. For 2003 the provision totaled $4.5 million as compared to $3.4 million in 2002. At December 31, 2003, the Company's estimates for site restoration of its petroleum and natural gas properties totaled approximately $57 million (2002 - $58 million), of which $21.1 million is currently reflected as an accumulated provision in the financial statements (2002 - $23.0 million).

WRITE-DOWN OF PETROLEUM AND NATURAL GAS PROPERTIES

The Company has recorded a provision of $10.4 million in 2003 (2002 - $31.3 million) in respect of impairment in certain non-core properties in Alberta, Saskatchewan and Montana.

INCOME TAXES

In 2003, Paramount recorded Large Corporations and other tax expense of $2.9 million as compared to $9.2 million in 2002. The 2002 tax expense includes approximately $5.7 million in respect of prior year tax assessments.

In 2003, the Alberta provincial and Canadian federal governments introduced legislation to reduce corporate income taxes. The changes are considered substantively enacted for the purposes of Canadian GAAP and, accordingly, the Company has recorded a future income tax benefit of $30.3 million in the current year.

The future income tax recovery recorded for 2003 totaled $62.2 million, as compared to $46.9 million in 2002.

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Estimated Income Tax Pools (millions of dollars)	December 31, 2003
Undepreciated capital costs (UCC)	$ 215
Canadian oil and gas property expenses (COGPE)	25
Canadian exploration expenses (CEE)	68
Canadian development expenses (CDE)	166
Other	21
Total estimated income tax pools	$ 495

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Paramount has available approximately $495 million of unutilized tax pools at December 31, 2003. These tax pools will be available for deduction in 2004 in accordance with Canadian income tax regulations at varying rates of amortization.

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CASH FLOW AND EARNINGS

(thousands of dollars)	2003	2002	2001
Cash flow from operations	$ 167,276	$ 259,916	$ 303,937
Cash flow from operations per share			
- basic	$ 2.78	$ 4.37	$ 5.11
- diluted	$ 2.77	$ 4.36	$ 5.11
Net earnings	$ 2,633	$ 10,307	$ 118,902
Earnings per share - basic	$ 0.04	$ 0.17	$ 2.00
- diluted	$ 0.04	$ 0.16	$ 2.00

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Paramount's cash flow from operations decreased 36 percent to $167.3 million from $259.9 million in 2002. Lower cash flows were primarily a result of $53 million in commodity hedging losses in 2003 as opposed to $47 million in commodity hedging gains in 2002, partially offset by a $50 million increase in petroleum and natural gas revenues due to higher commodity prices. A $40 million gain on sale of the investment in Peyto Exploration was also included in 2002 cash flows.

Fourth quarter cash flow totaled $43.2 million, a decrease of 30 percent from $62.1 million during the same period in 2002 (2001 - $47.7 million). The decrease in cash flow is a result of lower production levels as compared to the fourth quarter of 2002.

The Company recorded net earnings of $2.6 million, as compared to net earnings of $10.3 million in 2002. The lower earnings in 2003 are primarily due to lower cash flows, as well as the inclusion of $37 million Surmont compensation in 2002 net earnings.

QUARTERLY INFORMATION

Historical quarterly information, prepared by the Company in Canadian dollars and in accordance with GAAP, is as follows:

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(thousands of dollars, except per share amounts)	Fiscal 2003 Three Months Ended			
	Dec 31	Sep 30	Jun 30	Mar 31
Net revenues	$ 77,697	$ 66,004	$ 65,127	$ 90,507
Net earnings (loss)	$ 11,296	$ (7,851)	$ (1,436)	$ 624
Net earnings (loss) per common share - basic	$ 0.18	$ (0.13)	$ (0.02)	$ 0.01
- diluted	$ 0.18	$ (0.13)	$ (0.02)	$ 0.01

(thousands of dollars, except per share amounts)	Fiscal 2002 Three Months Ended			
	Dec 31	Sep 30	Jun 30	Mar 31
Net revenues	$110,180	$ 95,780	$ 110,206	$ 83,332
Net earnings (loss)	$(41,399)	$ 6,180	$ 26,614	$ 18,912
Net earnings (loss) per common share - basic	$ (0.70)	$ 0.10	$ 0.45	$ 0.32

- diluted	$ (0.70)	$ 0.10	$ 0.44	$ 0.32

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Quarterly net revenues in 2003, as compared to the same periods in 2002, reflect lower production volumes as a result of the disposition of the Trust assets in the first quarter of 2003, partially offset by higher commodity prices. Quarterly net earnings are lower in 2003 as compared to 2002 primarily due to reduced production levels, combined with commodity hedging losses incurred during the current year.

The net loss of $41.4 million in the fourth quarter of 2002 is primarily due to dry hole costs and impairment charges on non-core properties recorded in the quarter.

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CAPITAL EXPENDITURES

Capital Expenditures (thousands of dollars)	2003	2002	2001
Land	$ 22,288	$ 6,410	$ 39,166
Geological and geophysical	8,450	9,303	10,646
Drilling	123,455	124,076	127,736
Production equipment and facilities	69,560	77,407	94,775
Exploration and development expenditures	223,753	217,196	272,323
Summit Resources Limited acquisition	-	251,422	-
Property acquisitions	937	28,610	19,048
Proceeds received on property dispositions	(371,601)	(5,042)	(5,183)
Other	1,933	2,349	1,166
Net capital expenditures	$ (144,978)	$ 494,535	$ 287,354
Property, plant and equipment, net, December 31	$1,006,205	$1,411,961	$1,058,337
Total assets, December 31	$1,147,848	$1,526,786	$1,176,323

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During 2003, expenditures for exploration and development activities totaled $223.8 million as compared to $217.2 million in 2002 (2001 - $272.3 million). A total of 211 gross (139 net) wells were drilled during the year, including 67 gross (41 net) wells in the fourth quarter, compared to 135 gross (99 net) wells in 2002 (2001 - 196 gross, 159 net).

Net capital expenditures amounted to a recovery of $145.0 million in 2003 as compared to expenditures of $494.5 million in 2002 (2001 - $287.4 million). The Company disposed of a number of properties during 2003, including the Trust assets, resulting in a net capital recovery for the year.

INVESTMENTS

Short-Term Investments

The Company has the following short-term investments:

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	Opening 2003 Shares	Purchased (Sold)	Closing 2003 Shares	Investment
Investments				
Fox Creek Petroleum Corp.	2,173,162	152,000	2,325,162	$2,538,000
Invertek(1)	7,500,000	11,531,250	19,031,250	1,525,192
Spearhead Resources Inc.(2)				5,990,000
Altius Energy Corp.(3)				4,398,197
Harvest Energy Trust		200,000	200,000	2,100,000
Jurassic Oil and Gas Ltd.(4)	850,000	-	850,000	-
				$16,551,389

(1) Investment in Invertek is through Wilson Drilling Ltd.
(2) Spearhead Resources Inc. $5 million 8 percent and $990,000 10 percent secured convertible debentures due June 1, 2004.
(3) Altius Energy Corp. US $2.7 million 14 percent secured convertible debenture due April 9, 2005 plus accrued interest.
(4) The Company wrote off its investment in Jurassic Oil and Gas Ltd. in 2003.

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Investment in Drilling Company

Paramount owns a 50 percent equity interest in Wilson Drilling Ltd., a private company established to operate 3 drilling rigs in Western Canada. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

Investment in Drilling Partnership

Paramount owns a 99 percent interest in Shetah-Wilson Drilling Partnership, an entity established to operate 2 drilling rigs. The rigs are leased from an unrelated third party.

Investment in Pipeline Company

Paramount owns a 50 percent equity interest, before payout (45 percent after payout) in Shiha Energy Transmission Ltd., a private company established to transport natural gas from operations in the Liard core area, Northwest Territories to facilities in British Columbia. The Company accounts for its interest using proportionate consolidation.

Investment in Engineering Company

Paramount owns a 50 percent equity interest in a private company whose principal business is to provide consulting and technical engineering services. The Company accounts for its interest using proportionate consolidation.

DEFERRED REVENUE

During 2003, Paramount recognized in revenue $10.4 million (2002 - $39.4 million; 2001 - $1.2 million) of deferred revenue primarily related to the settlement of natural gas commodity hedging contracts that were previously put in place to mitigate the Company's commodity price risk. Paramount's accounting policy recognizes these gains in the accounting years of related production. The deferred hedging gains of $4.0 million at December 31, 2003 will be recognized in revenue in the first quarter of 2004.

LIQUIDITY AND CAPITAL RESOURCES

Paramount's capital structure as at December 31, 2003, was as follows:

/T/

(thousands of dollars, except per share amounts)	Amount	%	$/Share(1)
Debt			
US$ senior notes	$ 226,887	28	$ 3.78
Credit facility	60,350	7	1.00
Working capital deficiency	9,143	1	0.15
Other	11,324	1	0.19
Net debt	307,704	37	5.12
Shareholders' equity	501,642	63	8.35
Total capitalization	$ 809,346	100%	$13.47

(1)At December 31, 2003- 60,094,600 basic common shares outstanding.

/T/

Debt

On October 27, 2003, the Company closed an offering of US$175 million of senior unsecured notes due 2010. Net proceeds were used to reduce existing bank indebtedness. The Company also has a committed revolving/non-revolving credit facility with a syndicate of Canadian chartered banks. The revolving nature of the facility expires on March 31, 2004. The Company has requested for an extension of the revolving credit facility of up to 364 days, subject to the approval of the lenders. To facilitate the documentation of this extension, the Company has agreed to amend the expiry date of the existing facility to April 30, 2004. To the extent that any lenders participating in the syndicate do not approve the 364-day extension, the amount due to those lenders will convert to a one-year non-revolving term loan with principal due in full on March 31, 2005. The borrowing base under this facility was $203 million at December 31, 2003. The borrowing base is adjusted annually by the syndicate based on a review of the Company's financial and reserve reports; it is expected that this adjustment will be made early in 2004. The magnitude and direction of the adjustment are not known at this time.

The Company's working capital deficiency at December 31, 2003, excluding shareholder loan and bank loans, was $9.1 million (2002 - $16.0 million). Paramount will likely show a working capital deficiency on its balance sheet, as receivables related to petroleum and natural gas sales are collected in 30 days, whereas joint venture partners and suppliers are typically paid on 60 day terms.

Contractual Obligations

Future contractual obligations, as at December 31, 2003, are as follows:

/T/

	Expected Payment Date				
Contractual Obligations (thousands of dollars)	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
US$ senior notes due 2010	$226,887	-	-	-	$226,887
Pipeline commitments	268,686	25,692	45,808	43,773	153,413
Operating leases	35,700	4,109	8,367	8,443	14,781

Total	$531,273	$29,801	$54,175	$52,216	$395,081

/T/

Share Capital

As at December 31, 2003, the Company's issued share capital consisted of 60,094,600 common shares (December 31, 2002 - 59,458,600 common shares). Changes in share capital during 2002 and 2003 are as follows:

/T/

Common shares	Number	Consideration (thousands of dollars)
Balance December 31, 2001	59,453,600	$ 189,320
Stock options exercised	5,000	72
Expenses recognized in respect of stock-based compensation		801
Balance December 31, 2002	59,458,600	$ 190,193
Stock options exercised	710,000	10,317
Shares repurchased	(74,000)	(236)
Balance December 31, 2003	60,094,600	$ 200,274

/T/

In February 2003, employees of the Company exercised 710,000 stock options for total consideration of $10.3 million.

Pursuant to its Normal Course Issuer Bid, Paramount repurchased 74,000 common shares for cancellation in 2003, at an average price of $9.53 per share. From January 1 to March 12, 2004, the Company has repurchased a total of 701,300 common shares at an average price of $10.86 per share. Common shares outstanding at March 12, 2004 are 59,393,300.

For 2004, the Company expects to fund its capital expenditure program primarily through cash flow from operations, supplemented by available amounts under its credit facility.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has a 99 percent interest in a drilling partnership, which has a long-term operating lease on two drilling rigs operating in western Canada. The Company entered into the partnership in order to secure access to drilling rigs during peak demand periods. Future payments in respect of the operating lease are disclosed in Note 6 to the consolidated financial statements.

The Company's share of net operating income from the partnership amounted to $0.1 million in 2003 (2002 - loss of $0.8 million). These amounts have been recorded in the Company's consolidated statements of earnings.

RELATED PARTY TRANSACTIONS

Disposition of Assets to Paramount Energy Trust

In the first quarter of 2003, the Company transferred certain natural gas assets in Northeast Alberta to the Trust, a related party. The transaction, described under the heading "Significant Events", was accounted for at the net book value of the assets as recorded in Paramount.

Note Payable to Paramount Oil and Gas Ltd.

In 2002, in order to complement existing funding for the acquisition of Summit, the Company secured a $33 million loan from Paramount Oil and Gas Ltd., a related entity with a significant ownership interest in the Company. The loan was repaid on March 7, 2003.

RISKS AND UNCERTAINTIES

Companies involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. The Company's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short and long-term contract arrangements. Paramount utilizes a combination of these types of contracts, as well as spot markets, in its natural gas pricing strategy. As the majority of the Company's natural gas sales are priced to US markets, the Canada/US exchange rate can strongly affect revenue.

Oil prices are influenced by global supply and demand conditions as well as for worldwide political events. As the price of oil in Canada is based on a US benchmark price, variations in the Canada/US exchange rate further affect the price received by Paramount for its oil.

The Company's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Paramount intends to control as much of its marketing and transportation activities as possible in order to minimize any negative impact from these external factors.

The oil and gas industry is subject to extensive controls, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. The Company has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner intended to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Paramount's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and operating wells. The Company attempts to minimize these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Company recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Paramount has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Company's operations; however, the cost of complying with environmental regulations is increasing. Paramount intends to ensure continued compliance with environmental legislation.

2004 OUTLOOK AND SENSITIVITY ANALYSIS

The Company's earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Current volatility in commodity prices creates uncertainty as to Paramount's cash flow and capital expenditure budget. The Company will therefore assess results throughout the year and revise estimates as necessary to reflect most current information. The following analysis assesses the magnitude of these sensitivities on the Company's 2004 cash flow using the following base assumptions:

/T/

a) 2004 Production	
Natural gas	160 MMcf/d
Crude oil/liquids	6,000 Bbl/d
b) 2004 Average Prices	
Natural gas	$5.68/Mcf
Crude oil/liquids (W.T.I.)	US$28.00/Bbl
c) 2004 Exchange Rate (C$/US$)	$0.75

/T/

The following analysis assesses the estimated impact on cash flow with variations in production, prices, interest and exchange rates:

/T/

Sensitivity	Cash Flow Effect (millions of dollars)
Gas sales change of 10 MMcf/d	$ 16.6
Gas price change of $0.10/Mcf	$ 4.7
Oil and natural gas liquids sales change of 100 Bbl/d	$ 0.9
Oil and natural gas liquids price change of $1.00/Bbl (W.T.I)	$ 2.3
Sensitivity to Canada/US exchange rate fluctuation of $0.01 CDN	$ 0.5
Average interest rate change of 1%	$ 0.6

/T/

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Company's consolidated financial statements, which have been prepared in Canadian dollars in accordance with GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Paramount bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

The following is a discussion of the critical accounting estimates that are inherent in the preparation of the Company's consolidated financial statements and notes thereto.

Accounting for Petroleum and Natural Gas Operations

Under the successful efforts method of accounting, the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves, including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Exploration expenditures, including geological and geophysical costs, lease rentals, and exploratory dry holes are charged to earnings in the period incurred. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination is dependent upon, among other things, the results of planned additional wells and the cost of required capital expenditures to produce the reserves found.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze, and the determination that proved reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of exploratory costs related to drilling activity in a given area.

Reserve Estimates

Estimates of the Company's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Alberta Securities Commission. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

Paramount's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate.

The present value of future net revenues should not be assumed to be the current market value of the Company's estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations.

The estimates of reserves impact depletion, dry hole and site restoration expenses. If reserve estimates decline, the rate at which the Company records depletion and site restoration expenses increases, reducing net earnings. In addition, changes in reserve estimates may impact the outcome of Paramount's assessment of its petroleum and natural gas properties for impairment.

Impairment of Petroleum and Natural Gas Properties

The Company reviews its proved properties for impairment annually on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and probable petroleum and natural gas reserves, as estimated by the Company on the balance sheet date. Reserve estimates, as well as estimates for petroleum and natural gas prices and production costs may change, and there can be no assurance that impairment provisions will not be required in the future.

Unproved leasehold costs and exploratory drilling in progress are capitalized and reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling are charged to earnings. Acquisition costs for leases that are not individually significant are charged to earnings as the related leases expire. Further impairment expense could result if petroleum and natural gas prices decline in the future of if negative reserve revisions are recorded, as it may be no longer economic to develop certain unproved properties. Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales impacts the amount and timing of impairment provisions.

Future Site Restoration and Abandonment Costs

The site restoration provision recorded in the consolidated financial statements is based on an estimate for total costs for future site restoration and abandonment of the Company's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology and political and regulatory environments. Beginning in 2004, the Company will adopt the Canadian Institute of Chartered Accountants ("CICA") Handbook section 3110 - Asset Retirement Obligation, which will result in changes in accounting for site restoration and abandonment costs. See "Recent Accounting Pronouncements" section.

Income Taxes

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. We periodically assess the realizability of our future tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance.

RECENT ACCOUNTING PRONOUNCEMENTS

Impairment of Long-Lived Assets

The CICA recently issued Handbook Section 3063 - Impairment of Long-Lived Assets. This new section establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets by profit-oriented enterprises. The section is effective for fiscal years beginning on or after April 1, 2003.

Under the new section, impairment of long-lived assets held for use is determined by a two-step process, with the first step determining when an impairment is recognized and the second step measuring the amount of the impairment. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived asset's carrying amount exceeds its fair value. This represents a significant change to Canadian GAAP, which previously measured the amount of the impairment as the difference between the long-lived asset's carrying value and its net recoverable amount (i.e. undiscounted cash flows plus residual value). The Company anticipates that adoption of this pronouncement will not have a material effect on its consolidated financial statements.

Disposal of Long-Lived Assets and Discontinued Operations

The CICA recently issued Handbook Section 3475 - Disposal of Long-Lived Assets and Discontinued Operations, which establishes standards for the recognition, measurement, presentation and disclosure of the disposal of long-lived assets by profit-oriented enterprises. It also establishes standards for the presentation and disclosure of discontinued operations.

Although earlier adoption is encouraged, Section 3475 applies to disposal activities initiated by a company's commitment to a plan on or after May 1, 2003. The Company anticipates that adoption of this pronouncement will not have a material effect on its consolidated financial statements.

Variable Interest Entities

The CICA recently issued Accounting Guideline 15 - Consolidation of Variable Interest Entities. The guideline requires the consolidation of entities in which an enterprise absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority voting interest in the entity. The guideline applies to annual and interim periods beginning on or after November 1, 2004, except for certain disclosure requirements. Entities should provide disclosures about variable interest entities in which they hold significant interests for periods beginning on or after January 1, 2004. The Company does not expect the implementation of this guideline to have a material impact on its financial statements.

Asset Retirement Obligation

The CICA recently issued Handbook Section 3110 - Asset Retirement Obligation which addresses statutory, regulatory, contractual and other legal obligations associated with the retirement of a long-lived asset that results from its acquisition, construction, development or normal operation.

Under Section 3110, asset retirement obligations are initially measured at fair value at the time the obligation is incurred with a corresponding amount capitalized as part of the asset's carrying value and depreciated over the asset's useful life using a systematic and rational allocation method.

On initial recognition, the fair value of an asset retirement obligation is determined based upon the expected present value of future cash flows. In subsequent periods, the carrying amount of the liability would be adjusted to reflect (a) the passage of time, and (b) revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

The change in liability due to the passage of time is measured by applying an interest method of allocation to the opening liability and is recognized as an increase in the carrying value of the liability and an expense. The expense must be recorded as an operating item in the income statement, not as a component of interest expense. A change in the liability resulting from revisions to either the timing or the amount of the original estimate of undiscounted cash flows is recognized as an increase or decrease in the carrying amount of the liability with an offsetting increase or decrease in the carrying amount of the associated asset.

For the year ended December 31, 2003, property, plant and equipment would increase by $16.2 million, site restoration liability would increase by $38.2 million and retained earnings would decrease by $22.0 million.

Stock-Based Compensation and Other Stock-Based Payments

In December 2001, the CICA issued Handbook Section 3870 - Stock-Based Compensation and Other Stock-Based Payments, which requires fair value accounting for all stock-based payments to non-employees, and for employee awards that are direct awards of stock, or call for settlement in cash or other assets, and for stock appreciation rights. For all other employee awards, the present standard allows disclosure of pro forma net income and pro forma earnings per share in the income statement. In October 2003, the CICA amended Handbook Section 3870 to require recognition of expense, based on the fair value method, for all employee stock-based compensation transactions for fiscal years beginning on or after January 1, 2004.

The recommendations of the Section should also be applied to the following awards that were outstanding at the start of the first fiscal year beginning on or after January 1, 2002 in which adoption of this Section was initially applied:

(a) awards that call for settlement in cash or other assets;

(b) stock appreciation rights that call for settlement by the issuance of equity instruments; and

(c) any other award that is modified so as to become an award included in (a) or (b) above. The award should be accounted for as a new award, and not using modification accounting.

The cumulative amount, applicable to (a) or (b) above, that would have been recognized in prior years had this section been applied, less any amount previously recognized, should be recorded as the effect of a change in accounting policy and charged to opening retained earnings for the fiscal year in which this section is initially applied, without restatement of prior periods.

The Company adopted the fair-value method of accounting for stock options for fiscal 2003. The fair-value based method will be applied prospectively, whereby compensation costs will be recognized for all options granted on or after January 1, 2003. Adoption of this accounting policy has resulted in an expense of $1.2 million being recorded in the Company's financial statements for the year ended December 31, 2003.

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Consolidated Balance Sheets

As at December 31 (thousands of dollars)	2003	2002
ASSETS (note 7)		
Current Assets		
Short-term investments		
(market value: 2003 - $17,265; 2002 - $14,168)	$ 16,551	$ 14,168
Accounts receivable	84,183	91,042
Prepaid expenses	2,282	9,615
	103,016	114,825
Property, Plant and Equipment (note 5)		

Property, plant and equipment	1,420,540	1,961,369
Accumulated depletion and depreciation	(414,335)	(549,408)
	1,006,205	1,411,961
Goodwill (note 2)	31,621	-
Other Assets (note 8)	7,006	-
	$1,147,848	$1,526,786

LIABILITIES AND SHAREHOLDERS' EQUITY

Current Liabilities		
Accounts payable and accrued liabilities	$ 112,159	$ 130,798
Shareholder loan (note 9)	-	33,000
Bank loans (note 7)	1,450	498,097
	113,609	661,895
Long-term debt (note 8)	297,111	8,173
Provision for future site restoration and abandonment costs	21,114	22,954
Deferred revenue (note 12)	3,959	7,804
Future income taxes (note 11)	210,413	279,855
	532,597	318,786

Commitments and contingencies (notes 6, 12 and 14)

Shareholders' Equity		
Share capital (note 10)		
Issued and outstanding		
60,094,600 common shares (2002- 59,458,600 common shares)	200,274	190,193
Contributed surplus	746	-
Retained earnings	300,622	355,912
	501,642	546,105
	$1,147,848	$1,526,786

See accompanying notes to consolidated financial statements

On behalf of the Board of Directors

C. H. Riddell — Director

J.B. Roy — Director

Consolidated Statements of Earnings and Retained Earnings

Years ended December 31 (thousands of dollars except for per share amounts)	Three Months ended December 31 2003	Three Months ended December 31 2002	Year ended December 31 2003	Year ended December 31 2002
Revenue				
Petroleum and natural gas sales	$ 86,068	$ 134,608	$ 434,059	$ 384,188
Commodity hedging (loss) gain	1,541	893	(53,204)	46,813
Royalties (net of ARTC)	(10,664)	(28,157)	(82,512)	(74,444)
(Loss) gain on investments				

(note 16)	-	725	(1,020)	40,830
Other income	752	2,111	2,012	2,111
	77,697	110,180	299,335	399,498
Expenses				
Operating	22,287	23,474	81,193	86,067
Interest	5,604	9,727	19,917	23,943
General and administrative	5,832	5,768	19,898	16,212
Bad debt expense	-	-	5,977	-
Lease rentals	1,027	1,585	3,574	4,552
Geological and geophysical	3,208	1,182	8,450	9,303
Dry hole costs (note 5)	5,750	75,909	36,600	120,058
Loss (gain) on sales of property and equipment	(15,821)	121	3,660	(12)
Provision for future site restoration and abandonment costs	1,419	1,619	4,462	3,437
Depletion and depreciation	47,055	61,106	163,413	169,433
Write-down of petroleum and natural gas properties (note 5)	10,418	31,254	10,418	31,254
Unrealized foreign exchange gain on US debt (note 12)	(1,566)	-	(1,566)	-
Surmont compensation - net (note 15)	-	-	-	(37,291)
	85,213	211,745	355,996	426,956
Earnings (loss) before taxes	(7,516)	(101,565)	(56,661)	(27,458)
Income and other taxes (note 11)				
Large Corporations Tax and other	1,165	7,866	2,875	9,150
Future income tax recovery	(19,977)	(68,032)	(62,169)	(46,915)
	(18,812)	(60,166)	(59,294)	(37,765)
Net earnings (loss)	11,296	(41,399)	2,633	10,307
Retained earnings, beginning of period	294,861	397,311	355,912	346,064
Adjustment on disposition of assets to a related party (note 4)	(5,535)		(6,923)	-
Dividends declared (note 4)	-	-	(51,000)	-
Adoption of new accounting policies (note 3)	-	-	-	(459)
Retained earnings, end of year	$ 300,622	$ 355,912	$ 300,622	$ 355,912
Net earnings per common share (note 10)				
- basic	$ 0.18	$ (0.70)	$ 0.04	$ 0.17
- diluted	$ 0.18	$ (0.70)	$ 0.04	$ 0.16
Weighted average common shares outstanding (thousands) (note 10)				
- basic	60,168	59,459	60,098	59,458
- diluted	60,340	59,616	60,472	59,567

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

	Three Months ended December 31		Year ended December 31	
(thousands of dollars)	2003	2002	2003	2002
Operating activities				
Net earnings (loss)	$ 11,296	$ (41,399)	$ 2,633	$ 10,307
Add (deduct) non-cash items				
Depletion and depreciation	47,055	61,106	163,413	169,433
Write-down of petroleum and natural gas properties	10,418	31,254	10,418	31,254
Loss (gain) on sales of property and equipment	(15,821)	121	3,660	(12)
Provision for future site restoration and abandonment costs	1,419	1,619	4,462	3,437
Future income tax recovery	(19,977)	(68,032)	(62,169)	(46,915)
Amortization of other assets	161	342	161	-
Non-cash general and administrative expenses	1,214	-	1,214	342
Unrealized foreign exchange gain on US debt	(1,566)	-	(1,566)	-
Write-down of Surmont assets	-	-	-	9,136
Add items not related to operating activities				
Surmont compensation	-	-	-	(46,427)
Dry hole costs	5,750	75,909	36,600	120,058
Geological and geophysical costs	3,208	1,182	8,450	9,303
Cash flow from operations	43,157	62,102	167,276	259,916
Increase (decrease) in deferred revenue	3,218	(10,360)	(3,845)	6,073
Decrease in other assets	(161)		(161)	-
Change in non-cash operating working capital (note 13)	(20,531)	(26,453)	(33,381)	40,145
	25,683	25,289	129,889	306,134
Financing activities				
Bank loans - draws	33,272	19,376	43,013	153,682
Bank loans - repayments	(241,320)	(25,302)	(477,608)	(38,525)
Shareholder loan			(33,000)	33,000
Proceeds from US debt net of issuance costs	221,447	-	221,447	-
Capital stock - issued	(705)	-	10,317	72
Capital stock - repurchased			(705)	-
	12,694	(5,926)	(236,536)	148,229
Cash flow provided by operating and financing activities	38,377	19,363	(106,647)	454,363
Investing activities				
Property, plant and equipment expenditures	(83,225)	(14,615)	(217,295)	(209,848)
Acquisition of Summit Resources Ltd. (note 2)	-	-	-	(251,422)
Petroleum and natural gas property acquisitions	(228)	175	(228)	(28,420)
Geological and geophysical	(3,208)	(1,182)	(8,450)	(9,303)
Proceeds on sale of property, plant and equipment	45,937	(284)	317,792	4,423
Surmont compensation	-	-	-	46,427
Change in non-cash investing working capital (note 13)	2,347	(3,457)	14,828	(6,960)
Cash flow used in investing activities	(38,377)	(19,363)	106,647	(455,103)
(Decrease) increase in cash	-	-	-	(740)

Cash, beginning of year	-	-	-	740
Cash, end of year	$ -	$ -	$ -	$ -

See accompanying notes to consolidated financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all tabular amounts expressed in thousands of dollars)

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Paramount Resources Ltd. ("the "Company") is involved in the exploration and development of petroleum and natural gas primarily in Western Canada. The consolidated financial statements are stated in Canadian dollars and have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. These differences are quantified in note 18.

As a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's accounting policies summarized below.

(a) Principles of consolidation

The consolidated financial statements include the accounts of Paramount Resources Ltd. and its wholly owned subsidiaries, Paramount Resources U.S. LLC, 586319 Alberta Ltd., Summit Resources Limited, Summit Resources, Inc., 977554 Alberta Ltd. and 910083 Alberta Ltd.

The Company accounts for its interest in a drilling company, a drilling partnership, a pipeline company, and an engineering company where it exercises joint control using proportionate consolidation whereby its pro-rata shares of all assets, liabilities, revenues and expenses are combined on a line-by-line basis with similar items in the Company's financial statements.

(b) Joint operations

Certain of the Company's exploration, development and production activities related to petroleum and natural gas are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

(c) Revenue recognition

Revenues associated with the sale of natural gas, crude oil, and natural gas liquids ("NGL's") owned by the Company are recognized when title passes from the Company to its customer.

Revenues from oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest.

(d) Short-term investments

Short-term investments consist of common shares and convertible instruments held for sale. These investments are carried at the lower of cost and market value.

(e) Property, plant and equipment

Cost

Property, plant and equipment are recorded at cost. The Company follows the successful efforts method of accounting for petroleum and natural gas operations. Under this method the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net costs of unproductive exploratory wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of property, plant and equipment.

Depletion and depreciation

Depletion of petroleum and natural gas properties including well development expenditures is provided on the unit-of production method based on estimated proven recoverable reserves of each producing property or project. Depreciation of production equipment, gas plants and gathering systems is provided on a straight-line basis over their estimated useful life varying from 12 to 40 years. Depreciation of other equipment is provided on a declining balance method at rates varying from 4 to 30 percent.

Impairment

Producing areas and significant unproved properties are assessed annually, or as economic events dictate for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its undiscounted net recoverable amount.

(f) Future site restoration and abandonment costs

Estimated future site restoration and abandonment costs are provided for in the consolidated financial statements. This estimate, net of expected recoveries, includes the cost of equipment removal and environmental cleanup based upon current regulations and economic circumstances at year end. Actual site restoration costs are deducted from the provision in the year incurred.

(g) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is not amortized and is assessed by the Company for impairment at least annually. Impairment is assessed based on a comparison of the fair value of the net assets acquired to the carrying value of the net assets, including goodwill. Any excess of the carrying value of goodwill over and above its fair value is the impairment amount, and is charged to earnings in the period identified.

(h) Foreign currency translation

The Company's foreign operations are considered integrated and are translated into Canadian dollars using the temporal method.

Monetary assets and liabilities denominated in US dollars are translated into Canadian dollars at exchange rates in effect at the balance sheet date. Other assets and liabilities are translated at the rates prevailing at the respective transaction dates. Revenues and expenses are translated at the average rate prevailing during the year. Translation gains and losses are reflected in income when incurred.

(i) Financial instruments

The Company utilizes derivative financial instrument contracts such as forwards, futures, swaps and options to manage its exposure to petroleum and natural gas prices, the Canadian/U.S. dollar exchange rate and interest rate fluctuations. Gains or losses from foreign exchange and commodity hedge contracts are recognized as part of petroleum and natural gas sales in the same period as the related production revenue. Amounts received or paid under interest rate swaps are recognized in interest expense as incurred. The fair values of these contracts are not reflected in the consolidated financial statements. The Company does not enter into derivative instruments for trading or speculative purposes.

The Company's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified future revenue stream. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the notional amount, including the commodity price, exchange rate, and interest rate basis of the instruments, all match the terms of the future revenue stream being hedged.

Realized and unrealized gains or losses associated with derivative financial instrument contracts that have been terminated or cease to be effective prior to maturity are deferred as other current, or non-current, assets or liabilities on the balance sheet, as appropriate and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

(j) Measurement uncertainty

The amounts recorded for depletion and depreciation and impairment of petroleum and natural gas properties and equipment, and for site restoration and abandonment are based on estimates of reserves, future costs, petroleum and natural gas prices and other relevant assumptions. By their nature, these estimates and those related to the future cash flow used to assess impairment are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

(k) Income taxes

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

(l) Stock option plan

The Company has a stock-based compensation plan consisting of a stock option plan that is described in note 10.

Options granted under the Company's employee stock option plan are issued at current market value of the Company's stock. The fair value of the options issued is estimated at the date of grant and the compensation expense recognized over the expected life of the option. Consideration paid to the Company on exercise of the stock option is credited to share capital.

(m) Per common share amounts

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options and other dilutive instruments are used to purchase common shares at the average market price during the year.

2. ACQUISITION OF SUMMIT RESOURCES LIMITED

On May 12, 2002, Paramount and Summit Resources Limited ("Summit") jointly announced that they had entered into an agreement pursuant to which Paramount would make an offer to purchase all of the issued and outstanding common shares of Summit for cash consideration of $7.40 per share or approximately $249.6 million, including acquisition costs. This transaction has been accounted for using the purchase method and is being accounted for as of the closing date of June 28, 2002.

The Company has finalized the purchase price equation for this acquisition. The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition:

/T/

Assets	
Accounts receivable	$ 13,997
Petroleum and natural gas properties	419,642
Goodwill	31,621
	465,260
Liabilities	
Accounts payable	21,947
Future income taxes	108,373
Debt	74,513
Other liabilities	10,865
	215,698
Net assets acquired	$ 249,562

/T/

3. CHANGE IN ACCOUNTING POLICY

Stock-Based Compensation and Other Stock-Based Payments

The Canadian Institute of Chartered Accountants issued Handbook Section 3870, Stock-Based Compensation and Other Stock-Based Payments, which requires fair value accounting for all stock-based payments to non-employees, and for employees awards that are direct awards of stock, or call for settlement in cash or other assets, and for stock appreciation rights.

The Company adopted the fair-value method of accounting for stock options issued to employees and directors for fiscal 2003. For stock options, the fair-value based method has been applied prospectively, whereby compensation costs are recognized for all options granted or modified on or after January 1, 2003. Adoption of this accounting policy has resulted in an expense of $1.2 million ($0.02 per share) being recorded in the Company's consolidated financial statements for the year ended December 31, 2003. For share appreciation rights, the fair-value based method was applied retroactively without restatement in 2002. There was no impact on the 2003 consolidated financial statements (2002 - $0.5 million).

4. DISPOSITION OF ASSETS TO PARAMOUNT ENERGY TRUST

During the first quarter of 2003, the Company completed the formation and structuring of Paramount Energy Trust (the "Trust") through the following transactions:

a) On February 3, 2003, Paramount transferred to the Trust natural gas properties in the Legend area of Northeast Alberta for net proceeds of $28 million and 9,907,767 units of the Trust.

b) On February 3, 2003, Paramount declared a dividend-in-kind of $51 million, consisting of an aggregate of 9,907,767 units of the Trust. The dividend was paid to shareholders of Paramount's common shares of record on the close of business on February 11, 2003.

c) On March 11, 2003, in conjunction with the closing of a rights offering by the Trust, Paramount disposed of additional natural gas properties in Northeast Alberta to Paramount Operating Trust for net proceeds of $167 million.

As the transfer of the Initial Assets and the Additional Assets (collectively the "Trust Assets") represented a related party transaction not in the normal course of operations involving two companies under common control, the transaction has been accounted for at the net book value of the Trust Assets as recorded in the Company. Details are as follows:

/T/

Natural gas properties	$ 244,433
Future income tax liability	4,070
Site restoration liability	(5,900)
Costs of disposition	10,430
Adjustment to retained earnings	(6,638)
Net proceeds on disposition	$ 246,395

/T/

In connection with the creation and financing of the Trust and the transfer of natural gas properties to the Trust, the Company incurred costs of approximately $10.4 million. These costs have been included as a cost of disposition.

During 2003, the Company disposed of a minor non-core property to the Trust. The related party transaction was accounted for at the net book value of the assets, with an adjustment to retained earnings of $0.3 million.

5. PROPERTY PLANT AND EQUIPMENT

/T/

	2003		2002	
	Cost	Accumulated depletion and depreciation	Cost	Accumulated depletion and depreciation
Petroleum and natural gas properties	$ 961,248	$ 296,904	$ 1,263,544	$ 326,074
Gas plants, gathering systems and production				

equipment	430,234	107,031	670,769	214,655
Building	8,542	445	8,481	146
Other	20,516	9,955	18,575	8,533
	$ 1,420,540	$ 414,335	$ 1,961,369	$ 549,408
Net book value	$ 1,006,205		$ 1,411,961	

/T/

Capital costs associated with non-producing petroleum and natural gas properties totaling approximately $209 million (2002 - $367 million) are currently not subject to depletion.

For the year ended December 31, 2003, the Company expensed $36.6 million in dry hole costs (2002- $120.1 million). A portion of the dry hole costs expensed related to prior year capital projects that were determined in the current year to have no future economic value.

For the year ended December 31, 2003, the Company recorded a provision of $10.4 million (2002 - $31.3 million) in respect of impairment of petroleum and natural gas properties.

For the year ended December 31, 2003, the Company recorded a provision of $4.5 million (2002 - $3.4 million) in respect of future site restoration and abandonment costs.

6. JOINT VENTURES

The consolidated financial statements include the Company's proportionate share of the assets and liabilities of its joint ventures as follows:

/T/

	2003	2002
Assets		
Current assets	$ 5,116	$ 1,278
Property, plant and equipment	5,811	8,520
	$ 10,927	$ 9,798
Liabilities and equity		
Current liabilities	$ 8,421	$ 9,239
Other liabilities	4,284	2,008
Deficit	(1,778)	(1,449)
	$ 10,927	$ 9,798
Revenues	$ 11,594	$ 2,591
Expenses	$ 11,749	$ 2,396
Net earnings (loss)	$ (155)	$ 195
Cash flow provided by (used in)		
Operating activities	$ (1,564)	$ 3,452
Financing activities	$ 2,437	$ 1,063
Investing activities	$ (873)	$ (4,515)

/T/

On November 13, 2003, Wilson Drilling Ltd. replaced its existing term loan facility with a new $6.3 million credit facility with a Canadian chartered bank. The credit facility is repayable in equal monthly installments of $131,250 plus interest. As at

December 31, 2003, the facility had an effective interest rate of 4.67 percent. Wilson Drilling Ltd. also has a long-term capital lease on one of its drilling rigs with a Canadian chartered bank in the amount of approximately $3 million. The lease runs until August 2007 and has an imputed interest rate of 8.9 percent. The Company has provided a guarantee on the capital lease. Earnings attributed to services provided to the Company have been eliminated from the consolidated statements of earnings.

Shehtah-Wilson Drilling Partnership, a partnership in which the Company has a 99 percent interest, has a 10 year operating lease for two oilfield drilling rigs. The commitment associated with this lease is as follows:

/T/

Year	Lease Commitment
2004	$ 1,696
2005	1,696
2006	1,696
2007	1,696
2008	1,696
Thereafter	6,784
	$ 15,264

7. BANK LOANS

As at December 31, bank loans were comprised of:

	2003	2002
Production/working capital facility - (2002 - 7.5%)	$ -	$ 418,300
Drilling rig indebtedness - current interest rate of 6.00% (2002 - 6.82%)	1,138	3,071
Mortgage - current interest rate of 6.15%	312	270
Bridge facility - (2002 - 13%)	-	44,900
LIBOR advances - (2002 - 7.75%)	-	31,556
	$ 1,450	$ 498,097

/T/

The Company has letters of credit totaling $10.3 million (2002 - $13.3 million) outstanding with a Canadian Chartered Bank. These letters of credit reduce the amount available under the Company's working capital facility.

8. LONG-TERM DEBT

As at December 31, long term debt was comprised of:

/T/

	2003	2002
U.S. Senior Notes - interest rate of 7.875%	$ 226,887	$ -
Credit facility - current interest rate of 4.5%	60,350	-

Drilling rig indebtedness - current interest rate of 6.00% (2002 - 6.82%)	3,456	1,443
Mortgage - interest rate of 6.15%	6,418	6,730
	$ 297,111	$ 8,173

/T/

The Company issued U.S. $175 million of 7 7/8 percent Senior Notes due 2010 on October 27, 2003. Interest on the notes is payable semi-annually, beginning in 2004. The Company may redeem some or all of the notes at any time after November 1, 2007 at redemption prices ranging from 100 percent to 103.938 percent of the principal amount, plus accrued and unpaid interest to the redemption date, depending on the year in which the notes are redeemed. In addition, the Company may redeem up to 35 percent of the notes prior to November 1, 2006 at 107.875 percent of the principal amount, plus accrued interest to the redemption date, using the proceeds of certain equity offerings. The notes are unsecured and rank equally with all of the Company's existing and future unsecured indebtedness.

The Company incurred $7.1 million of financing charges in 2003 related to the issuance of the senior notes. The financing charges are capitalized to other assets and amortized evenly over the term of the notes.

On October 27, 2003, the Company replaced its existing credit facility with a new $203 million committed revolving/non-revolving term facility with a syndicate of Canadian chartered banks. Borrowings under the facility bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 50 to 300 basis points, dependent on certain conditions. The revolving nature of the new facility expires on March 31, 2004. The Company has requested for an extension of the revolving credit facility of up to 364 days, subject to the approval of the lenders. To facilitate the documentation of this extension, the Company has agreed to amend the expiry date of the existing facility to April 30, 2004. To the extent that any lenders participating in the syndicate do not approve the 364 day extension, the amount due to those lenders will convert to a one year non-revolving term loan with principal due in full on March 31, 2005. Advances drawn on the facility are secured by a first floating charge over all the assets of the Company.

The Company has an office building which was acquired as a result of the acquisition of Summit Resources Limited. The building is mortgaged at an interest rate of 6.15 percent over a term of 5 years ending December 31, 2007.

9. RELATED PARTY TRANSACTIONS

Disposition of Assets to Paramount Energy Trust

In the first quarter of 2003, the Company transferred certain natural gas assets in Northeast Alberta to the Trust, a related party. The transaction (see note 4), was accounted for at the net book value of the assets as recorded in the Company.

Note Payable to Paramount Oil and Gas Ltd.

In 2002, in order to complement existing funding for the acquisition of Summit, the Company secured a $33 million loan, with an effective interest rate during 2002 of 5.5 percent, from Paramount Oil and Gas Ltd., a related entity with a significant ownership interest in the Company. The loan was repaid on March 7, 2003.

10. SHARE CAPITAL

Authorized Capital

The authorized capital of the Company is comprised of an unlimited number of non-voting preferred shares without nominal or par value, issuable in series, and an unlimited number of common shares without nominal or par value.

Issued Capital

/T/

Common Shares	Number	Consideration
Balance December 31, 2001	59,453,600	$ 189,320
Stock options exercised during the year	5,000	72
Expenses recognized in respect of stock-based compensation during the year	-	801
Balance December 31, 2002	59,458,600	$ 190,193
Stock options exercised during the year	710,000	10,317
Shares repurchased - at par	(74,000)	(236)
Balance December 31, 2003	60,094,600	$ 200,274

/T/

The Company instituted a Normal Course Issuer Bid to acquire a maximum of 5 percent of its issued and outstanding shares commencing May 15, 2003, and ending May 14, 2004. During 2003, 74,000 shares (2002 - nil) were purchased pursuant to the plan at an average price of $9.53 per share.

Subsequent to year-end, the Company re-purchased 701,300 common shares at an average price of $10.86 per share.

In February 2003, employees of the Company exercised 710,000 stock options for total consideration of $10.3 million.

Stock Option Plan

The Company has an Employee Incentive Stock Option plan (the "plan"). Under the plan, stock options are granted at the current market price on the date of issuance. Participants in the plan, upon exercising their stock options, may request to receive either a cash payment equal to the difference between the exercise price and the market price of the Company's common shares or common shares issued from Treasury. Irrespective of the participant's request, the Company may choose to only issue common shares. Cash payments made in respect of the plan are charged to general and administrative expenses when incurred. Options granted vest over four years and have a four and a half year contractual life.

As at December 31, 2003, 5.9 million shares were reserved for issuance under the Company's Employee Incentive Stock Option Plan, of which 3.6 million options are outstanding, exercisable to September 30, 2008, at prices ranging from $8.91 to $12.02 per share.

The formation of the Trust (note 4) resulted in the Company re-pricing stock options. 941,500 stock options issued in 2001, the majority of which were at exercise prices of $14.50 and $13.35 per option, were re-priced to exercise prices of $10.22 and $9.07 per option, respectively.

/T/

Stock options	2003		2002	
	Average grant price	Options	Average grant price	Options
Balance, beginning of year	$14.25	1,949,500	$14.08	2,173,500
Granted	9.66	2,998,000	15.90	80,000
Exercised	14.29	(791,000)	12.98	(195,000)
Cancelled	10.30	(524,500)	14.23	(109,000)
Balance, end of year	$ 9.64	3,632,000	$14.25	1,949,500
Options exercisable, end of year	$10.72	1,087,875	$14.35	738,500

The following summarizes information about stock options outstanding at December 31, 2003:

	Outstanding			Exercisable	
Exercise Prices	Number	Weighted Average Contractual Life	Weighted Average Exercise Price	Exercisable Number	Weighted Average Exercise Price
$ 8.91-9.80	2,506,000	4	$ 9.02	309,375	$ 9.00
$ 10.01-12.02	1,126,000	2	$ 11.04	778,500	$ 11.40
Total	3,632,000	3	$ 9.64	1,087,875	$ 10.72

/T/

Fair Values

The fair values of all common share options granted are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted average fair values of the options granted during the year and the weighted average assumptions used in their determination are as noted below:

/T/

	2003	2002
Risk-free interest rate	5.8%	5.8%
Expected life	4 years	4 years
Expected volatility	39%	39%
Fair value per option	$3.42	$6.38

/T/

The Company recognized compensation costs related to stock options granted to employees of $1.2 million. The Company recognized no compensation costs related to stock options granted to employees in 2002. Had compensation costs for stock options granted to employees in 2002 been determined based on the fair value at the grant date of the awards, $49,000 would have been charged to earnings in 2002, for which there was no impact on earnings per share. Options granted prior to 2003 continue to be accounted for through pro-forma disclosure.

Per Share Information

Basic earnings per share are calculated based on a weighted average number of common shares of 60,098,447 (2002 - 59,457,737). There are no anti-dilutive options at December 31, 2003.

11. INCOME TAXES

The income tax provision differs from the expected income taxes obtained by applying the Canadian corporate tax rate to loss before taxes as follows:

/T/

	2003	2002
Corporate tax rate	40.67%	42.14%
Calculated income tax recovery	$ (23,044)	$ (11,571)
Increase (decrease) resulting from:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	21,991	10,449
Federal resource allowance	(17,124)	(29,958)
Federal and provincial income tax rate adjustment	(30,257)	(2,758)
Attributed Canadian Royalty Income recognized	(5,228)	-
Large corporations tax and other	2,875	9,150
Non-taxable portion of gain on sale of investments	-	(8,603)
Recognition of tax pools not previously recognized	(3,343)	-
Other	(5,164)	(4,474)
Income tax recovery expense	$ (59,294)	$ (37,765)

Components Of Future Income Taxes

The net future tax liability comprises:	2003	2002
Differences between tax base and reported amounts of depreciable assets	$ 215,250	$ 285,201
Provision for future site restoration	(7,310)	(7,255)
Other	2,473	1,909
	$ 210,413	$ 279,855

/T/

12. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the consolidated balance sheet are comprised of short-term investments, accounts receivable, accounts payable, shareholder loan, bank loans, long-term debt and deferred revenue.

(a) FOREIGN EXCHANGE HEDGES

The Company has entered into the following currency index swap transactions, fixing the exchange rate on receipts of US $24.4 million for CDN $34.9 million over the next two years at CDN $1.4335. The US$/CDN$ closing exchange rate was 1.2965 as at December 31, 2003 (December 31, 2002 - 1.5776).

/T/

Year of settlement	U.S. dollars	Weighted average exchange rate
2004	$ 12,360	1.4333
2005	12,000	1.4337
	$ 24,360	1.4335

/T/

At December 31, 2003 the estimated fair value of these hedges based on the Company's assessment of available market information was a gain of $3.3 million (2002 - loss of $6.0 million).

(b) COMMODITY PRICE HEDGES

At December 31, 2003, the Company has entered into financial forward sales arrangements as follows:

/T/

AECO	Price	Term
10,000 GJ/d	$7.35	January 2004 - March 2004
10,000 GJ/d	$6.26	January 2004 - March 2004
10,000 GJ/d	$6.14	January 2004 - March 2004
20,000 GJ/d	$6.51	January 2004 - March 2004
10,000 GJ/d	$5.55	April 2004 - October 2004
10,000 GJ/d	$5.51	April 2004 - October 2004
WTI		
1,000 Bbl/d	US$24.07	May 2002 - April 2004
1,000 Bbl/d	(collar) US$25.00-$30.25	January 2004 - December 2004

/T/

Had these financial contracts been settled on December 31, 2003, using prices in effect at that time, the mark to market before tax loss would have totaled $1.6 million (2002 - $28.7 million).

Subsequent to December 31, 2003, the Company entered into financial agreements as follows:

/T/

AECO	Price	Term
10,000 GJ/d	$5.81	April 2004 - October 2004
10,000 GJ/d	$5.86	April 2004 - October 2004
20,000 GJ/d	$5.80	April 2004 - October 2004
10,000 GJ/d	(collar) $5.25-$6.80	April 2004 - October 2004
10,000 GJ/d	(collar) $5.25-$6.75	April 2004 - October 2004

/T/

(c) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Borrowings under bank credit facilities and the issuance of commercial paper are for short periods and are market rate based, thus, carrying values approximate fair value. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at year-end. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices available to the Company.

The fair values of other financial instruments, including accounts receivable, accounts payable, shareholder loan, bank loans and deferred revenue, approximate their carrying values due to the short-term maturity of those instruments.

The fair values of the mortgage and drilling rig indebtedness approximate their carrying values, as there have been no significant changes in long-term interest rates from the dates these liabilities were incurred to the balance sheet date.

The fair value of the U.S. Senior Notes approximate their carrying values, as the debt has been translated into Canadian dollars at exchange rates in effect at the balance sheet date, and there have been no significant changes in long-term interest rates from the dates these liabilities were incurred to the balance sheet date.

(d) CREDIT RISK

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties and controls third party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures. The Company sells production to a variety of purchasers under normal industry sale and payment terms. The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risks.

(e) INTEREST RATE RISK

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's debts that have a floating interest rate. The Company had no interest rate swaps or hedges at December 31, 2003.

13. CHANGE IN NON-CASH WORKING CAPITAL

/T/

	2003	2002
Change in non-cash working capital:		
Short-term investments	$ (283)	$ (236)
Accounts receivable	6,859	(18,686)
Prepaid expenses	1,829	(5,893)
Deferred hedging loss	-	17,638
Accounts payable and accrued liabilities	(26,958)	48,312
Less working capital deficiency acquired (note 2)	-	(7,950)

	$ (18,553)	$ 33,185
Operating activities	(33,381)	40,145
Investing activities	14,828	(6,960)
	$ (18,553)	$ 33,185

/T/

Certain changes in non-cash working capital which were incurred as a result of asset dispositions during the year have been excluded from the above amounts.

Amounts paid during the year related to interest and large corporations and other taxes were as follows:

/T/

	2003	2002
Interest paid	$ 17,497	$ 23,278
Large corporations and other taxes paid	$ 2,395	$ 20,447

/T/

14. CONTINGENCIES AND COMMITMENTS

Contingencies

The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial position.

The Company indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Company to the extent permitted by law. The Company has acquired and maintains liability insurance for its directors and officers.

Commitments

As at December 31, 2003, the Company has the following commitments related to the operating lease for the building and pipeline commitments.

/T/

Year	Commitment
2004	$ 25,695
2005	23,925
2006	21,889
2007	21,889
2008	21,889
Thereafter	153,421
	$ 268,708

/T/

15. SURMONT COMPENSATION

During 2000, the Alberta Energy and Utilities Board issued a decision regarding the Surmont natural gas bitumen co-production issue. As a result of this decision, the Board ordered the shut-in of approximately 22 MMcf/d of the Company's production. On February 28, 2002, the Company and the Surmont Gas Producers entered into a Memorandum of Agreement with the Province of Alberta effective May 1, 2000. The Memorandum provided for compensation of approximately $85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of reduced royalties, as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11% gross overriding royalty encompassing certain wells, land and leases affected by the shut-in order of May 1, 2000.

In 2002, the company received approximately $46.4 million in the form of reduced royalties from the Province of Alberta as compensation for its proportionate share of the settlement. The cash settlement, net of the net book value of wells, lands and leases in the affected area of approximately $9 million, has been recorded in net earnings in 2002.

16. GAIN ON SALE OF INVESTMENTS

During 2002, the Company recorded gains on disposal of its investments in Peyto Exploration and Development Corp. and other short-term investments of $40.8 million.

17. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

18. RECONCILIATION OF FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Any differences in accounting principles as they pertain to the accompanying financial statements are not material except as described below. The application of United States generally accepted accounting principles ("U.S. GAAP") would have the following effects on the Company's historical net earnings (loss) as reported:

/T/

	Year ended December 31, 2003	Year ended December 31, 2002
Net earnings for the year as reported	$ 2,633	$ 10,307
Adjustments, net of tax		
Forward foreign exchange contracts and other financial instruments(a)	3,411	(25,267)
Impairments and related change in depletion(c)	6,762	(15,138)
Depletion and depreciation(d)	(1,734)	
General and administrative(d)	141	-
Short-term investments(f)	428	
Net earnings (loss) for the year before changes in accounting policies - U.S. GAAP(e)	$ 11,641	$ (30,098)
Change in accounting policy - Asset Retirement Obligation(d)	-	(15,633)
Net earnings (loss) for the year - U.S. GAAP	$ 11,641	$ (45,731)

Net earnings (loss) per common share before change in accounting policy - U.S. GAAP(e)		
Basic	$ 0.19	$ (0.51)
Diluted	$ 0.19	$ (0.51)
Net earnings (loss) per common share - U.S. GAAP(e)		
Basic	$ 0.19	$ (0.77)
Diluted	$ 0.19	$ (0.77)

The application of U.S. GAAP would have the following effect on the balance sheet at December 31:

	2003		2002	
	As reported	U.S. GAAP	As reported	U.S. GAAP
Assets				
Short-term investments(f)	$ 16,551	$ 17,265	$ 14,168	$ 14,168
Assets held for sale(e)	-	-	-	193,899
Property, plant and equipment(c)(d)(e)	1,006,205	1,022,366	1,411,961	1,225,138
Liabilities				
Deferred hedging loss (gain)(a)	$ -	$ 1,726	$ -	$ 43,667
Provision for future site restoration and abandonment costs(d)	21,114	59,301	22,954	56,575
Deferred Revenue(a)	3,959	-		
Future income taxes(a)(b)(c)(d)(f)	210,413	222,163	279,855	253,971
Shareholders' equity				
Retained earnings	$ 300,622	$ 273,245	$ 355,912	$ 311,584

/T/

(a) Forward foreign exchange contracts and other financial instruments-The Company has designated, for Canadian GAAP purposes, its derivative financial instruments as hedges of anticipated revenue and expenses. In accordance with Canadian GAAP, payments or receipts on these contracts are recognized in income concurrently with the hedged transaction. The fair values of the contracts deemed to be hedges are not reflected in the financial statements.

For U.S. purposes, the Company has adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, Accounting for Derivative Instruments and Hedging Activities. With the adoption of this standard all derivative instruments are recognized on the balance sheet at fair value. The statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Management has not designated any of the currently held financial instruments as hedges for U.S. GAAP purposes and accordingly these derivatives have been recognized on the balance sheet at fair value with the change in their fair value recognized in earnings.

Under U.S. GAAP for the year ended December 31, 2003 additional income of $5.7 million (net of tax - $3.4 million) and for the year ended December 31, 2002 additional expense of $43.7 million (net of tax - $25.3 million) would have been recorded.

(b) Deferred Income Taxes-The Canadian liability method of accounting for income taxes is similar to the United States Statement of Financial Accounting Standard No. 109 "Accounting for Income Taxes", which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Pursuant to U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted rates. For the years ended December 31, 2003 and 2002 this difference did not impact the Company's financial position or results of operations.

(c) Impairments-Under both U.S. and Canadian GAAP, property, plant and equipment must be assessed for potential impairments. Under U.S. GAAP, if the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, then an impairment loss (the amount by which the carrying amount of the asset exceeds the fair value of the asset) should be recognized. Fair value is calculated as the present value of estimated expected future cash flows. As disclosed in note 1, under Canadian GAAP, the impairment loss is the difference between the carrying value of the asset and its net recoverable amount (discounted). For the year ended December 31, 2003, no impairment charge would be recorded and a reduction in depletion expense of $11.3 million (net of tax - $6.8 million) would be recorded due to impairment charges recorded in fiscal 2002 under U.S. GAAP. For the year ended December 31, 2002, an additional impairment charge of $49.0 million (net of tax - $28.3 million), and a reduction in depletion expense of $23.0 million (net of tax - $13.1 million) would have been recorded under U.S. GAAP. The resulting differences in recorded carrying values of impaired assets result in further differences in depreciation, depletion and amortization expense in subsequent years.

The Canadian Institute of Chartered Accountants (the "CICA") has adopted a new standard that will eliminate this U.S./Canadian GAAP difference going forward.

(d) Asset Retirement Obligations - For U.S. purposes, the Company has adopted Statement of Financial Accounting Standards ("SFAS") No. 143, Accounting for Asset Retirement Obligations. Under U.S. GAAP, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of long-lived assets must be recognized at fair value in the period in which the liability is incurred. The fair value is added to the carrying amount of the associated asset. The liability is accreted at the end of each period through charges to operating expenses.

For the year ended December 31, 2003, the change results in an additional reduction to site restoration expense of $0.2 million (net of tax - $0.1 million) and an additional charge to depletion and depreciation of $2.9 million (net of tax - $1.7 million). The effect on the Consolidated Balance Sheet is an increase in property, plant and equipment of $16.2 million and an increase of $38.2 million to the provision for future site restoration and abandonment costs.

For the year ended December 31, 2002, the cumulative impact results in an additional charge due to a change in accounting policy of $20.1 million (net of tax of $15.6 million). The cumulative effect on the Consolidated Balance Sheet is an increase in property, plant and equipment of $36.4 million, an increase to site restoration liability of $33.6 million.

(e) Discontinued Operations-Under U.S. GAAP, the transaction resulting in the disposal of the Trust Assets to the Trust as described in note 4 would be accounted for as discontinued operations as the applicable criteria set out in SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets" had been met. Accordingly, the carrying value of the Trust Assets are separately presented in the consolidated balance sheet. Net income from discontinued operations for the year ended December 31, 2003 would have been $11.6 million (2002 - net loss - $5.7 million), or $0.19 per basic and diluted common share (2002 - loss of $0.10 per basic and diluted common share).

(f) Short-Term Investments - Under U.S. GAAP, equity securities that are bought and sold in the short term are classified as trading securities. Unrealized holding gains and losses related to trading securities are included in earnings as incurred. Under Canadian GAAP, these gains and losses are not recognized in earnings until the security is sold. As at December 31, 2003 the Company had unrealized holding gains of $0.7 million (net of tax - $0.4 million).

(g) Other Comprehensive Income-Under U.S. GAAP, certain items such as the unrealized gain or loss on derivative instrument contracts designated and effective as cash flow hedges are included in other comprehensive income. In these financial statements, there are no comprehensive income items other than net earnings.

(h) Statements of Cash Flow-The application of U.S. GAAP would not change the amounts as reported under Canadian GAAP for cash flows provided by (used in) operating, investing or financing activities, except that the consolidated statements of cash flow include, under investing activities, changes in working capital for items not affecting cash, such as accounts payable related to the non-cash elements of property and equipment reductions of $14,828 (2002 - additions of $6,960). This disclosure has been provided in order to disclose the aggregate costs related to such activities and to arrive at the cash amounts. This presentation is not permitted under U.S. GAAP.

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Paramount Resources Limited
Pro-forma Supplemental Oil and Gas Operating Statistics - unaudited
For the Period Ended December 31, 2003
(Note 1)

Sales Volumes	2003			
	Q4	Q3	Q2	Q1
Gas (MMcf/d)	141	136	142	143
Oil and Natural Gas Liquids (Bbl/d)	5,877	7,461	7,465	7,892
Total Sales Volumes (Boe/d) (6:1)	29,353	30,098	31,129	31,711

Per-unit Results	2003			
	Q4	Q3	Q2	Q1
Produced Gas ($/Mcf)				
Price, net of transpiration and selling	5.14	5.74	5.90	6.91
Royalties	0.55	1.30	1.14	1.43

Operating expenses, net of processing revenue	1.26	1.19	0.95	0.73
Netback before commodity hedge	3.33	3.25	3.81	4.75
Commodity hedge	0.25	(0.72)	(1.09)	(1.62)
Netback including commodity hedge	3.58	2.53	2.72	3.13

Produced Oil & Natural Gas Liquids ($/Bbl)				
Price, net of transpiration and selling	36.02	36.48	36.94	42.98
Royalties	6.64	6.75	7.28	9.04
Operating expenses, net of processing revenue	11.01	10.01	8.90	6.96
Netback before commodity hedge	18.37	19.72	20.76	26.98
Commodity hedge	(3.13)	(2.27)	(1.67)	(4.03)
Netback including commodity hedge	15.24	17.45	19.09	22.95

Total Produced ($/Boe)				
Price, net of transpiration and selling	31.87	34.95	35.84	41.85
Royalties	3.95	7.56	6.95	8.70
Operating expenses, net of processing revenue	8.25	7.85	6.46	5.02
Netback before commodity hedge	19.67	19.54	22.43	28.13
Commodity hedge	0.57	(3.76)	(5.37)	(8.33)
Netback including commodity hedge	20.24	15.78	17.06	19.80

Sales Volumes	2002			
	Q4	Q3	Q2	Q1
Gas (MMcf/d)	172	162	182	170
Oil and Natural Gas Liquids (Bbl/d)	8,552	7,832	7,346	8,362
Total Sales Volumes (Boe/d) (6:1)	37,243	34,756	37,732	36,739

Per-unit Results	2002			
	Q4	Q3	Q2	Q1
Produced Gas ($/Mcf)				
Price, net of transpiration and selling	4.15	3.16	4.05	2.80
Royalties	0.92	0.65	0.91	0.49
Operating expenses, net of processing revenue	0.64	0.70	1.05	0.64
Netback before commodity hedge	2.59	1.81	2.09	1.67
Commodity hedge	0.29	0.67	0.50	0.75
Netback including commodity hedge	2.88	2.48	2.59	2.42

Produced Oil & Natural Gas Liquids
($/Bbl)

Price, net of transpiration and selling	36.03	37.47	33.82	27.28
Royalties	6.83	8.71	5.97	3.78
Operating expenses, net of processing revenue	5.72	8.40	5.75	6.18
Netback before commodity hedge	23.48	20.36	22.10	17.32
Commodity hedge	(0.76)	(0.76)	-	-
Netback including commodity hedge	22.72	19.60	22.10	17.32

Total Produced ($/Boe)

Price, net of transpiration and selling	27.44	23.14	26.15	19.20
Royalties	5.80	4.99	5.56	3.12
Operating expenses, net of processing revenue	4.29	5.15	6.22	4.36
Netback before commodity hedge	17.35	13.00	14.37	11.72
Commodity hedge	1.15	2.96	2.40	3.48
Netback including commodity hedge	18.50	15.96	16.77	15.20

Note 1 - Pro-forma is presented on the basis of combining the results of Paramount and Summit Resources Limited for periods prior to the acquisition of Summit and removing the results associated with the properties that were part of the Trust Disposition for periods or as of dates prior to the Trust Disposition.

Note 2 - The Alberta Securities Commission released National Instrument 51-101 (the "Instrument") in 2003, with an effective date of September 30, 2003.

The instrument requires all reported petroleum and natural gas production to be measured in marketable quantities with adjustments for heat content included in the commodity price reported.

The Company has adopted the Instrument prospectively. As such, fourth quarter natural gas production volumes are measured in marketable quantities, with adjustments

Paramount Resources Ltd.
Pro-forma Quarterly Condensed Statements of Earnings - Unaudited
For 2002 and 2003

$000's	2003			
	Q4	Q3	Q2	Q1
Net revenue, before hedging	$ 76,156	$ 76,427	$ 80,345	$ 101,050
Commodity hedging gain (loss)	1,541	(10,423)	(15,218)	(29,100)
Net revenue	77,697	66,004	65,127	71,950
Operating expenses	22,287	21,738	18,302	14,338
Interest	5,604	3,017	4,234	4,476
General and administrative	5,832	4,709	4,589	4,513
Lease rentals	1,027	1,070	702	775
Geological and geophysical	3,208	1,071	3,423	748
Dry hole costs	5,750	1,533	13,628	8,891
Depletion and depreciation	47,055	33,175	37,041	38,759
Other expenses	(5,550)	5,512	31,866	733
	85,213	71,825	113,785	73,233
Earnings (loss) before taxes	(7,516)	(5,821)	(48,658)	(1,283)
Current and large corporations tax	1,165	422	741	547

Future tax (recovery)	(19,977)	1,608	(47,963)	370
Net earnings (loss)	$ 11,296	$ (7,851)	$(1,436)	$ (2,200)
Net earnings (loss) per common share				
- basic	$ 0.19	$ (0.13)	$ (0.02)	$ (0.04)
- diluted	$ 0.19	$ (0.13)	$ (0.02)	$ (0.04)
Cash flow from operations	$ 43,157	$ 29,071	$36,559	$ 47,301
Cash flow from operations per common share				
-basic	$ 0.72	$ 0.48	$ 0.61	$ 0.79
-diluted	$ 0.72	$ 0.47	$ 0.61	$ 0.79
WA shares o/s (basic)	60,168	60,169	60,169	59,998
WA shares o/s (diluted)	60,340	60,287	60,244	60,072

	2002			
	Q4	Q3	Q2	Q1
Net revenue, before hedging	$ 77,000	$ 58,046	$ 95,202	$ 68,752
Commodity hedging gain (loss)	3,925	9,466	8,233	11,497
Net revenue	80,925	67,512	103,435	80,249
Operating expenses	14,709	16,468	21,339	14,408
Interest	9,367	4,670	3,140	2,097
General and administrative	4,850	3,821	3,689	3,579
Lease rentals	899	1,343	227	632
Geological and geophysical	1,182	1,238	6,991	1,003
Dry hole costs	115,909	963	2,308	2,444
Depletion and depreciation	49,726	33,975	36,131	35,371
Other expenses	(8,126)	1,114	3,490	(40)
	188,516	63,592	77,315	59,494
Earnings (loss) before taxes	(107,591)	3,920	26,120	20,755
Current and large corporations tax	1,989	(479)	11,375	1,027
Future tax (recovery)	(74,272)	333	(6,043)	3,090
Net earnings (loss)	$ (35,308)	$ 4,066	$ 20,788	$ 16,638
Net earnings (loss) per common share				
- basic	$ (0.59)	$ 0.07	$ 0.35	$ 0.28
- diluted	$ (0.59)	$ 0.07	$ 0.35	$ 0.28
Cash flow from operations	$ 49,111	$41,689	$ 63,665	$ 58,506
Cash flow from operations per common share				
-basic	$ 0.83	$ 0.70	$ 1.07	$ 0.98
-diluted	$ 0.82	$ 0.70	$ 1.07	$ 0.98
WA shares o/s (basic)	59,458	59,459	59,457	59,459
WA shares o/s (diluted)	59,581	59,616	59,524	59,544

Paramount Resources Ltd.
Condensed Balance Sheets - Unaudited
As at December 31, 2003 and 2002
$000's

	(Pro forma - Note 1) 2003	2002
Current assets	$ 103,016	$ 119,366
Property, plant and equipment	1,006,205	1,132,311
Other assets		31,621
Total assets	$ 1,147,848	$ 1,283,298
Accounts payable	$ 112,159	$ 140,396
Debt	298,561	289,269
Future income taxes	210,413	308,996
Other liabilities	25,073	23,647
Shareholders' equity	501,642	520,990
Total liabilities & shareholders' equity	$ 1,147,848	$ 1,283,298

Note 1:
The unaudited Pro forma condensed consolidated balance sheet and statements of earnings have been prepared to reflect both the acquisition of Summit Resources Limited (the "Summit acquisition") and the disposition of assets to Paramount Energy Trust (the "Trust disposition"), as follows:

i) The balance sheet at December 31, 2002 gives effect to the Trust disposition as though it had occurred on December 31, 2002.
ii) The statements of earnings for the quarters ended March 31, 2002 and June 30, 2002 give effect to the Summit acquisition as though it had occurred on the first day of the respective quarter.
iii) The statements of earnings for the quarters ended March 31, 2002, June 30, 2002, September 30, 2002, December 31, 2002 and March 31, 2003 give effect to the Trust disposition as though it had occurred on the first day of the respective quarter.

The unaudited Pro forma condensed consolidated balance sheet and statements of earnings may not be indicative of the financial position and results of operations that would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future.

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