Form 51-101F1
Statement of Reserves Data and Other Oil & Gas Information

REVISED

NOTICE OF CHANGES MADE TO ORIGINAL FILING

1. Cautionary language on the 6:1 conversion ratio has been added.
2. The wording of certain phrases has been changed. Instead of referring to "established reserves", the term "Total Proved Reserves" has been used and instead of referring to "Present Worth", the term "Net Present Value" .
3. The Net Present Value of both before and after tax is now disclosed for both the Constant Price and Forecast Price cases.
4. Discount rates of 15% and 20% have been added to the Net Present Value of Future Net Revenue.
5. Additional information on Future Net Revenue has been added for both the Constant Price and Forecast Price cases, without discount and a 10% discount rate.
6. A section for Forward Contracts has been added.
7. The Reserves Reconciliation section has been added to explain the opening differences from 2003. In addition, the Reconciliation has been expanded and presently differently from the original presentation to clarify subsections.
8. The Future Net Revenue Reconciliation has been added.
9. Future Development Costs have been added.
10. Properties With No Attributed Reserves has been added.
11. Forward Contracts have been added.
12. Production Estimates has been added.
13. Abandonment and Reclamation Costs have been added.
14. Tax Horizon has been added.

1. Dates

The effective date of this report is December 31, 2004. A report was prepared by Chapman Petroleum Engineering Ltd. ("Chapman"), the Company's independent reserve auditor in April, 2005. This statement is dated May 26, 2005.

All properties evaluated in this report are located in Alberta, Canada.

For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet ("mcf") to one barrel of oil. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with NI 51-101. Boes may be misleading, particularly if used in isolation.

2. Reserves Data

2.1 (1) Reserves and Constant Prices and Costs

	Arbour Energy Inc. interest in reserves			
	Oil (Mbbls)	NGL's (Mbbls)	Natural Gas (MMscf)	Total (Mboe)
Proved Developed Producing	28.0	0.0	176.0	57.33
Proved Developed Non Producing	0.0	0.0	57.0	9.50
Proved Undeveloped	0.0	0.0	0.0	0.0
Total Proved Reserves	28.0	0.0	233.0	185.66

2.1 (2) Net Present Value of Future Net Revenue (Constant Case)

	Net Present Value of Future Net Revenue before income tax ($ thousands)		Net Present Value of Future Net Revenue after income tax ($ thousands)	
	Undiscounted	10%	Undiscounted	10%
Proved Developed Producing	1,744	1,393	1,490	1,230
Proved Developed Non Producing	203	150	137	104
Proved Undeveloped	0	0	0	0
Total Proved Reserves	1,948	1,543	1,628	1,334

The following constant prices were used to calculate the reserve value for Arbour.

Year	Inflation %/yr	Exchange rate US/$CDN	WTI $US/Bbl	Crude Oil Light Sweet Edmonton $Cdn/bbl	Natural Gas AECO spot $Cdn/mmbtu
2005	1.5%	0.82	42.00	50.22	6.55

2.1 (3) Total Future Net Revenue, Without Discount (Constant Case)

Proved Reserves

	Amount ($M)
Revenue	$3,165
Royalties	195
Operating Costs	800
Development Costs	10
Well Abandonment Costs	250
Future Net Revenue, before income taxes	1,948
Income Taxes	320
Future Net Revenue, after income taxes	$1,628

2.1 (3)(c) Future Net Revenue Before Income Tax, Discounted at 10% (ConstantCase)

Proved Developed Producing	M$
Pembina	1,031
Kirkpatrick Lake	340
Company ARTC	22
Total Proved Developed Producing	1,393
Proved Developed Non-Producing	
Kirkpatrick Lake	144
Company ARTC	6
Total Proved Developed Non-Producing	150
Total Proved Developed	1,543

2.2 (1) Reserves (Forecast prices and costs)

	Crude Oil (Mbbls)	NGL's (Mbbls)	Natural Gas (MMscf)	Total (Mboe)
Proved Developed Producing	28.0	0.0	173.0	56.33
Proved Developed Non Producing	0.0	0.0	57.0	9.50
Proved Undeveloped	0.0	0.0	0.0	0.00
Total Proved Reserves	28.0	0.0	231.0	66.50
Probable	20.0	0.0	591.0	118.50
Proved Plus Probable Reserves	48.0	0.0	822.0	185.00

2.2 (2) Net Present Value of Future Net Revenue (Forecast prices and costs)

BEFORE INCOME TAX	**Discounted at**

	0%	5%	10%	15%	20%
Proved Developed Producing	1,588	1,423	1,296	1,195	1,111
Proved Developed Non Producing	179	155	136	122	110
Proved Undeveloped	0	0	0	0	0
Total Proved Reserves	1,767	1,578	1,432	1,317	1,222
Probable	2,637	1,826	1,363	1,064	861
Proved Plus Probable Reserves	4,404	3,404	2,795	2,381	2,083

AFTER INCOME TAX	**Discounted at**				
	0%	**5%**	**10%**	**15%**	**20%**
Proved Developed Producing	1,385	1,263	1,165	1,086	1,020
Proved Developed Non Producing	122	105	95	86	77
Proved Undeveloped	0	0	0	0	0
Total Proved Reserves	1,507	1,369	1,259	1,171	1,097
Probable	1,755	1,215	902	700	562
Proved Plus Probable Reserves	3,262	2,584	2,161	1,871	1,659

2.2 (3) Future Net Revenue Without Discount (Forecast Case)

Proved Reserves

	Amount ($M)
Revenue	$3,026
Royalties	185
Operating Costs	835
Development Costs	10
Well Abandonment Costs	265
Future Net Revenue, before income taxes	1,767
Income Taxes	260
Future Net Revenue, after income taxes	$1,507

2.2 (3)(c) Future Net Revenue Before Income Tax Discounted at 10% (Forecast Case)

Proved Developed Producing	M$
Pembina	960
Kirkpatrick Lake	315
Company ARTC	21
Total Proved Developed Producing	1,296
Proved Developed Non-Producing	
Kirkpatrick Lake	131
Company ARTC	6
Total Proved Developed Non-Producing	136
Total Proved Developed	1,432

3. Pricing Assumptions

The following prices for the first five years were used to calculate the reserve value for the forecasted price case.

Year	Inflation %/yr	Exchange rate $US/$CDN	WTI $US/Bbl	Crude Oil Light Sweet Edmonton $Cdn/bbl	Natural Gas AECO spot Cdn/mmbtu
2005	1.5	0.82	42.00	50.22	6.55
2006	1.5	0.80	40.00	49.00	6.30
2007	1.5	0.78	38.00	47.72	5.80
2008	1.5	0.78	36.00	45.15	5.55
2009	1.5	0.78	35.00	43.87	5.63

4.1 Reserves Reconciliation

The company proved working interest producing reserves for the 2003 calendar year was 2.2 mboe from one well in the Pembina area. Total proved plus probable reserves at the end of 2004 of 170.07 mboe is attributed to the 6 producing Pembina wells and one well in Kirkpatrick Lake.

The following table sets forth a reconciliation of the changes in Arbour's light and medium oil and associated and non-associated gas reserves. In accordance with NI 51-101 it is no longer necessary to reconcile secondary products including solution gas and NGL's.

	Light and Medium Oil (mbbls)			Associated and Non-Associated Gas (mmcf)		
	Total Proved	Total Probable	Total Proved Plus Probable	Total Proved	Total Probable	Total Proved Plus Probable
REMAINING RESERVES						
Total at Dec. 31, 2003	1.4	0.8	2.2	0.0	0.0	0.0
Total at Dec. 31, 2004	28.3	19.6	47.9	173.0	560.0	733.0
Overall Difference	26.9	18.8	45.7	173.0	560.0	733.0
RESERVE RECONCILIATION						
Production (sales)	0.4	0.0	0.4	0.0	0.0	0.0
Acquisitions	27.1	18.9	46.0	173.0	560.0	733.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0

Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0
Revisions to Previous Estimates						
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Technical	0.2	-0.1	0.1	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0

Notes:
(1) Columns may not add due to rounding.

4.2 Future Net Revenue Reconciliation

Net Proved Reserves Constant Price and Costs and 10% Discount Rate

Item		Value
	Future Revenue Prediction at Previous Year End	M$ 84
i)	Net value of sales	M$ (35)
ii)	Net change in production costs for future production	M$ 11
ii)	Net change in sales prices for future production	M$ 9
ii)	Net change in royalties for future production	M$ 0
iii)	Change in Development costs incurred	M$ 0
iv)	Change in Future development cost	M$ 0
v)	Change from extension & improved recovery	M$ 0
vi)	Acquisitions	M$ 1,162
vii)	Dispositions	M$ 0
ix)	Revision in quantity estimates	M$ 4
x)	Accretion of discount (10% of discounted future net revenue at beginning of year)	M$ 5
xi)	Net change in income taxes	M$ 15
xii)	Other factors	M$ 79
	Future Revenue Prediction at current year end	M$ 1,334

5.3 Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Constant Prices and Costs	Forecast Prices and Costs	
	Proved Reserves	Proved Reserves	Proved Plus Probable Reserves
	M$	M$	M$
2005	10.0	10.0	242.0
2006	0.0	0.0	0.0
2007	0.0	0.0	0.0
2008	0.0	0.0	0.0
2009	0.0	0.0	0.0
Remaining years	0.0	0.0	0.0
Total Undiscounted	10.0	10.0	242.0
Total Discounted at 10% per year	9.5	9.5	230.0

Arbour estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above.

6.1 Oil and Gas Wells

The following tables set forth the number and status of wells in which Arbour had a material working interest as at December 31, 2004, which were producing or which Arbour considered to be capable of production.

	Producing				**Shut-in** [1]			
	Oil		**Natural Gas**		**Oil**		**Natural Gas**	
	Gross [2]	**Net** [3]	**Gross** [2]	**Net** [3]	**Gross** [2]	**Net** [3]	**Gross** [2]	**Net** [3]
Pembine	6.0	5.225	5.0	5.0	0	0	0	0
Kirkpatrick Lake	0	0	1.0	1.0	0	0	3.0	3.0
Lochend	0	0	0	0	0	0	1.0	1.0
Total	6.0	5.225	6.	6.	0	0	4.0	4.0

Notes:

(1) "**Shut-in**" wells means wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons.

(2) "**Gross**" wells are the total number of wells in which the Corporation has an interest.

(3) "**Net**" wells are the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

6.2 Properties With No Attributed Reserves

There are no work commitments.

6.3 Forward Contracts

The Company does not have any “hedge” contracts in place at this time.

6.4 Abandonment and Reclamation Costs

Abandonment costs are estimated utilizing the AEUB abandonment and restoration and liability calculation spreadsheet. This method accounts for the general areas, number of zones to be abandoned, well depth and presence of tubing and rods, etc. Separate amounts are determined for abandonment and lease restoration. The abandonment cost determined is net of salvage.

The Company expects to incur abandonment costs on 8.3 net wells at an undiscounted amount of $357,352 and $203,087 at a 10% discount rate. Of the $357,352, $60,000 (of the $203,087, $17,000 discounted) was not deducted as abandonment and reclamation costs in estimating the future net revenue. Over the next three years, the company expects to pay $105,124 in abandonment costs.

6.5 Tax Horizon

The Corporation anticipates that it will be taxable in the year 2007.

6.7 Drilling History

The following table sets forth the number of gross and net wells which Arbour drilled or participated in drilling during the periods indicated.

	Year Ended Dec. 31,			
	2004		**2003**	
	Gross (1)	**Net (2)**	**Gross (1)**	**Net (2)**
Natural gas	1	0.25	1.0	1.0
Crude oil	0	0	0	0
Natural gas and crude oil	0	0	0	0
Dry and abandoned	0	0	0	0
Total	1	0.25	1.0	1.0

Notes:

(1) "**Gross**" means the number of wells in which the Corporation has a working interest.

(2) "**Net**" means the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

(3) "**Dry**" refers to a well that is not productive. A productive well is a well which is capable of producing in quantities considered by the operator to be sufficient to justify the costs required to complete, equip and produce the well.

Undeveloped Land

The following table summarizes the Corporation's interest in its undeveloped land holdings as at December 31, 2004.

Area	**Gross (1)**	**Net (2)**
	(acres)	
Bow Island	1280	640
Kirkpatrick Lake	160	80
Total	1,440	720

Notes:
(1) "**Gross**" refers to the total acres in which the Corporation has an interest.
(2) "**Net**" refers to the total acres in which the Corporation has an interest, multiplied by the percentage working interest therein owned by the Corporation.

6.8 Production Estimates

Pembina Year 2005		**Oil (STB)**	**Gas (MCF)**
# of wells		6	-
Price/STB/MCF		$49.13	$7.85
STB/D		28.7	81.9
Volume		10,474	30
Company share	Gross	9,329	19
	Net	9,232	17

Kirkpatrick Lake Year 2005		**Oil (STB)**	**Gas (MCF)**
# of wells		-	1
Price/STB/MCF		-	$7.06
STB/D		-	89.6
Volume		-	31
Company share	Gross	-	16
	Net	-	14

Total Production Estimates 2005		**Oil (STB)**	**Gas (MCF)**
# of wells		6	1
Price/STB/MCF		49.13	$7.49
STB/D		28.7	167.8
Volume		10,474	61
Company share	Gross	9,329	34
	Net	9,232	31

6.9 Production History, Prices Received and Capital Expenditures

The following table sets forth certain information in respect of production, product prices received, royalties, operating expenses, netbacks received, and capital expenditures made by the Corporation for each quarter in the most recently completed financial year of the Corporation, with comparative data for the same periods in the preceding financial year.

	Three Months Ended		Three Months Ended		Three Months Ended		Three Months Ended	
	Dec. 31, 2004	Dec. 31, 2003	Sept. 30, 2004	Sept. 30, 2003	June 30, 2004	June 30, 2003	Mar. 31 2004	Mar. 31 2003
Average daily production								
Crude oil (bbls/d)	18.4	1.6	1.3	1.6	1.1	2.4	1.3	3.2
NGL (bbls/d)	2.5	0.3	0.4	0.2	0.1	0.2	0.1	0.1
Natural gas (mcf/d)	7.0	17.0	2.7	14.6	2.6	10.1	2.2	6.7
Combined (boe)	27.9	4.7	4.3	4.2	3.8	4.3	3.5	4.3
Average Net Prices Received								
Crude oil ($/bbl)	52.37	38.00	54.97	39.86	50.5	34.4	43.3	5.09
NGL ($/bbl)	41.97	41.63	45.68	48.36	39.2	42.3	88.8	.
Natural gas ($/mcf)	7.06	5.48	6.80	6.28	7.64	5.48	6.95	9.08
Combined ($/boe)	49.0	37.50	45.4	41.97	47.0	36.53	43.9	52.29
Royalties								
Crude oil ($/bbl)	0	0.	0	0.	0	0.	0	0.
NGL ($/bbl)	7.26	0.	0	0.	0	0.	0	0.
Natural gas ($/mcf)	1.73	0.	0	0.	0	0.	0.41	0.
Combined ($/boe)	3.25	0.	0	0.	0	0.	1.49	0.
Operating Expenses								
Crude oil ($/bbl)	26.4	21.39	17.0	17.64	13.6	19.80	42.1	14.49
NGL ($/bbl)	0.	0.	0.	0.	0.	0.	0.	0.
Natural gas ($/mcf)	2.3	1.24	2.8	1.85	2.3	0.89	7.1	0.74
Combined ($/boe)	21.0	28.83	15.4	28.74	13.2	25.14	40.7	18.93
Netback Received								
Crude oil ($/bbl)	26.0	16.66	38.0	22.22	37.0	14.6	1.2	35.6
NGL ($/bbl)	34.7	0.	45.68	0.	39.2	0.	0	0.
Natural gas ($/mcf)	3.0	4.24	4.0	4.43	5.4	4.59	0.4	8.33
Combined ($/boe)	25.0	8.67	30.0	13.22	33.8	11.39	1.8	33.36
Capital Expenditures ($m)								
Property acquisitions	1,040.0	0	549.0	0	0	0	0	0
Exploration, including drilling	0.0	0	62.3	0	0	0	0	802.8
Development, including facilities	6.0	0	0.0	0	0	0	0	127.4
Other	0.0	0	16.0	0	0	0	0	0
Total Capital Expenditures	1,046.0	0	627.3	0	0	0	0	930.2

Notes:

(1) Before deduction of royalties.

(2) Product prices are net of hedging costs and are net of costs to transport the product to market.

(3) Royalties are net of ARTC.

(4) This figure includes all field operating expenses.

(5) Arbour does not record operating expenses on a commodity basis. Information in respect of operating expenses for crude oil ($/bbl), NGL ($/bbl) and natural gas ($/mcf) has been determined by allocating expenses on an area by area basis based on the relative volume of production of crude oil, NGL and natural gas in those areas.

(6) Information in respect of netbacks received for crude oil ($bbl), NGL ($/bbl) and natural gas ($/mcf) is calculated using operating expense figures for crude oil ($/bbl), NGL ($/bbl) and natural gas ($/mcf), which figures have been estimated. See note (5) above.

Marketing

Arbour sells natural gas production to a major natural gas aggregator. The Corporation receives a price that is calculated on the monthly average, based on the daily spot price at the AECO-C Hub. There is no requirement for the Corporation to provide a specified volume of natural gas pursuant to the contracts.

Arbour delivers NGL to Penn West. The price received by the Corporation is determined by reference to the monthly spot price and the Corporation is obligated to deliver all volumes to such aggregators.

The Corporation's crude oil production is marketed to Nexen crude oil aggregators. The Corporation receives monthly average spot pricing, less differentials and tariffs, and the Corporation is obligated to deliver all volumes to such aggregators.

From time to time, the Corporation may enter into hedging transactions that are negotiated to help protect its ability to achieve the capital budget. To date no such agreements have been entered into.

Future Commitments

As at the date hereof, the Corporation has not made any material commitments to buy, sell, exchange or transport crude oil and natural gas.

Cyclical and Seasonal Impact of Industry

The Corporation's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the Corporation's financial condition.

Renegotiation or Termination of Contracts

As at the date hereof, Arbour does not anticipate that any aspect of Arbour's business will be materially affected in 2005 by the renegotiation or termination of contracts or subcontracts.

Competitive Conditions

Arbour is a member of the petroleum industry, which is highly competitive at all levels. The Corporation competes with other companies for all of its business inputs, including exploration and development prospects, access to commodity markets, and available capital.

The Corporation strives to be competitive by maintaining a strong financial condition and by utilizing current technologies to enhance exploration, development and operational activities. The Corporation recognizes that it is a small player in the industry and, as such, seeks profitable joint venture relationships in order to access the technical and industry expertise of other companies.

Arbour competes with others in this area, bidding for mineral rights at Crown land sales and acquiring producing properties and working interests in projects already partly owned. To mitigate the effects of competition, Arbour generally tries to obtain operatorship and to own as large a working interest as possible in its producing properties to control the access to, and timing of, its field operations, particularly drilling.

Environmental Considerations

The Corporation is pro-active in its approach to environment concerns. Procedures are in place to ensure that the utmost care is taken in the day to day management of its oil and gas properties. All government regulations and procedures are followed in strict adherence to the law. The Corporation believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to the Corporation.

The Corporation's estimated asset retirement obligations are recognized at their fair value when the related asset is acquired and a reasonable estimate of its fair value is determinable. Discounted future cash flows are used to measure fair value. When a liability is recognized, a corresponding asset retirement cost is capitalized to the carrying amount of the related asset. The asset retirement cost is amortized over the estimated useful of the related asset. The Corporation recognizes changes to the liability due to the passage of time in operating expenses, as accretion. The Corporation recognizes changes to the liability arising from revisions to the timing or amount of expected future cash flows as an increase or decrease to the carrying amounts of the asset retirement obligation and the related asset retirement capitalized cost. As at December 31, 2004, the Corporation had an asset retirement obligation in the amount of $260,643.