FORM 51-101F1

STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION

BOW VALLEY ENERGY LTD.

April 22, 2004

The effective date of the information being provided in this statement is December 31, 2003. The preparation date of the information being provided in this statement is March 18, 2004. For a glossary of terminology and definitions relating to the information included within this statement (including the aforementioned dates), readers are referred to National Instrument 51-101 ("NI 51-101").

Reserves and Future Net Revenue

The following is a summary of the oil and natural gas reserves and the net present values of future net revenue of Bow Valley Energy Ltd. and its subsidiaries (the "Company") as evaluated by Ryder Scott Company ("Ryder Scott"), in the case of the Company's Canadian reserves data, and by APA Petroleum Engineering ("APA"), in the case of the Company's United Kingdom reserves data. Both Ryder Scott and APA are independent qualified reserves evaluators appointed by the Company pursuant to NI 51-101. Substantially all of the Company's oil and gas properties with reserves in Canada and the United Kingdom were independently evaluated by Ryder Scott and APA, respectively.

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Ryder Scott and APA Reports will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the Ryder Scott and APA Reports. The recovery and reserves estimates attributed to the Company's properties described herein are estimates only. The actual reserves attributed to the Company's properties may be greater or less than those calculated.

TABLE 2.1A

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2003
CONSTANT PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
CANADA						
PROVED						
Developed Producing	29.9	29.2	6,378	4,856	147.9	108.9
Developed Non-Producing	-	-	1,854	1,490	26.0	18.7
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	29.9	29.2	8,232	6,346	173.9	127.6
PROBABLE	12.7	12.5	3,027	2,355	59.4	43.8
TOTAL PROVED PLUS PROBABLE	42.6	41.7	11,259	8,701	233.3	171.4
UNITED KINGDOM						
PROVED						
Developed Producing	290.0	290.0	2,860	2,860	-	-
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	540.0	540.0	4,410	4,410	-	-
TOTAL PROVED	830.0	830.0	7,270	7,270	-	-
PROBABLE	11,800.0	10,880.0	14,400	13,650	-	-
TOTAL PROVED PLUS PROBABLE	12,630.0	11,710.0	21,670	20,920	-	-
TOTAL COMPANY						
PROVED						
Developed Producing	319.9	319.2	9,238	7,716	147.9	108.9
Developed Non-Producing	-	-	1,854	1,490	26.0	18.7
Undeveloped	540.0	540.0	4,410	4,410	-	-
TOTAL PROVED	859.9	859.2	15,502	13,616	173.9	127.6
PROBABLE	11,812.7	10,892.5	17,427	16,005	59.4	43.8
TOTAL PROVED PLUS PROBABLE	12,672.6	11,751.7	32,929	29,621	233.3	171.4

TABLE 2.1B

SUMMARY OF OIL AND GAS
NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003
CONSTANT PRICES AND COSTS

	NET PRESENT VALUES OF FUTURE NET REVENUE					
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)			AFTER INCOME TAXES DISCOUNTED AT (%/year)		
	0	5	10	0	5	10
RESERVES CATEGORY	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
CANADA						
PROVED						
Developed Producing	23.4	20.2	18.1	23.4	20.2	18.1
Developed Non-Producing	7.6	6.6	5.8	7.6	6.6	5.8
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	31.0	26.8	23.9	31.0	26.8	23.9
PROBABLE	11.3	8.6	7.0	11.3	8.6	7.0
TOTAL PROVED PLUS PROBABLE	42.3	35.4	30.9	42.3	35.4	30.9
UNITED KINGDOM						
PROVED						
Developed Producing	1.1	1.4	1.6	1.1	1.4	1.6
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	19.4	16.7	14.5	18.9	16.3	14.2
TOTAL PROVED	20.5	18.1	16.1	20.0	17.7	15.8
PROBABLE	200.4	137.9	95.6	119.2	79.7	53.0
TOTAL PROVED PLUS PROBABLE	220.9	155.9	111.7	139.1	97.4	68.8
TOTAL COMPANY						
PROVED						
Developed Producing	24.5	21.6	19.7	24.5	21.6	19.7
Developed Non-Producing	7.6	6.6	5.8	7.6	6.6	5.8
Undeveloped	19.4	16.7	14.5	18.9	16.3	14.2
TOTAL PROVED	51.5	44.9	40.0	51.0	44.5	39.7
PROBABLE	211.7	146.5	102.6	130.5	88.3	60.0
TOTAL PROVED PLUS PROBABLE	263.2	191.3	142.6	181.4	132.8	99.7

TABLE 2.1C

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2003
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
CANADA								
Proved Reserves	56,056	10,920	12,564	919	674	30,979	-	30,979
Proved Plus Probable Reserves	76,236	14,835	17,445	983	714	42,259	-	42,259
UNITED KINGDOM								
Proved Reserves	63,040	-	30,550	8,030	3,980	20,480	500	19,980
Proved Plus Probable Reserves	587,590	38,910	177,160	137,060	13,600	220,860	81,710	139,150
TOTAL COMPANY								
Proved Reserves	119,096	10,920	43,114	8,949	4,654	51,459	500	50,959
Proved Plus Probable Reserves	663,826	53,745	194,605	138,043	14,314	263,119	81,710	181,409

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	**Light and Medium Crude Oil (including solution gas and other by-products)**	16,270
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	23,749
Proved Plus Probable Reserves	**Light and Medium Crude Oil (including solution gas and other by-products)**	112,031
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	30,605

TABLE 2.2A

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2003
FORECAST PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMCF)	Gross (Mbbl)	Net (Mbbl)
CANADA						
PROVED						
Developed Producing	16.5	18.0	6,232	4,755	145.9	108.6
Developed Non-Producing	-	-	1,846	1,492	26.0	19.0
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	16.5	18.0	8,078	6,247	171.9	127.6
PROBABLE	6.9	7.3	2,961	2,316	58.2	43.6
TOTAL PROVED PLUS PROBABLE	23.4	25.3	11,039	8,563	230.1	171.2
UNITED KINGDOM						
PROVED						
Developed Producing	290.0	290.0	2,860	2,860	-	-
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	540.0	540.0	4,410	4,410	-	-
TOTAL PROVED	830.0	830.0	7,270	7,270	-	-
PROBABLE	11,800.0	10,880.0	14,400	13,650	-	-
TOTAL PROVED PLUS PROBABLE	12,630.0	11,710.0	21,670	20,920	-	-
TOTAL COMPANY						
PROVED						
Developed Producing	306.5	308.0	9,092	7,615	145.9	108.6
Developed Non-Producing	-	-	1,846	1,492	26.0	19.0
Undeveloped	540.0	540.0	4,410	4,410	-	-
TOTAL PROVED	846.5	848.0	15,348	13,517	171.9	127.6
PROBABLE	11,806.9	10,887.3	17,361	15,966	58.2	43.6
TOTAL PROVED PLUS PROBABLE	12,653.4	11,735.3	32,709	29,483	230.1	171.2

TABLE 2.2B

SUMMARY OF OIL AND GAS
NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003
FORECAST PRICES AND COSTS

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					AFTER INCOME TAXES DISCOUNTED AT (%/YEAR)				
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
CANADA										
PROVED										
Developed Producing	18.4	16.1	14.5	13.3	12.4	18.4	16.1	14.5	13.3	12.4
Developed Non-Producing	6.1	5.3	4.7	4.3	4.0	6.1	5.3	4.7	4.3	4.0
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	24.5	21.4	19.2	17.6	16.4	24.5	21.4	19.2	17.6	16.4
PROBABLE	8.6	6.6	5.5	4.7	4.1	8.6	6.6	5.5	4.7	4.1
TOTAL PROVED PLUS PROBABLE	33.1	28.0	24.7	22.3	20.5	33.1	28.0	24.7	22.3	20.5
UNITED KINGDOM										
PROVED										
Developed Producing	(1.0)	(0.6)	(0.3)	0.0	0.3	(1.0)	(0.6)	(0.3)	0.0	0.3
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	13.7	11.9	10.4	9.1	8.1	13.7	11.9	10.4	9.1	8.1
TOTAL PROVED	12.6	11.3	10.1	9.1	8.3	12.6	11.3	10.1	9.1	8.3
PROBABLE	114.0	76.0	49.9	32.0	19.7	67.2	43.0	26.1	14.5	6.6
TOTAL PROVED PLUS PROBABLE	126.7	87.3	60.0	41.2	28.0	79.8	54.3	36.2	23.6	14.9
TOTAL COMPANY										
PROVED										
Developed Producing	17.4	15.5	14.2	13.3	12.7	17.4	15.5	14.2	13.3	12.7
Developed Non-Producing	6.1	5.3	4.7	4.3	4.0	6.1	5.3	4.7	4.3	4.0
Undeveloped	13.7	11.9	10.4	9.1	8.1	13.7	11.9	10.4	9.1	8.1
TOTAL PROVED	37.1	32.7	29.3	26.7	24.7	37.1	32.7	29.3	26.7	24.7
PROBABLE	122.6	82.6	55.4	36.7	23.8	75.8	49.6	31.6	19.2	10.7
TOTAL PROVED PLUS PROBABLE	159.8	115.3	84.7	63.5	48.5	112.9	82.3	60.9	45.9	35.4

TABLE 2.2C

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2003
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
CANADA								
Proved Reserves	47,404	9,152	12,112	919	727	24,494	-	24,494
Proved Plus Probable Reserves	64,123	12,303	17,001	983	783	33,053	-	33,053
UNITED KINGDOM								
Proved Reserves	57,100	-	31,980	8,160	4,340	12,620	-	12,620
Proved Plus Probable Reserves	499,790	33,330	180,640	142,560	16,600	126,660	46,860	79,800
TOTAL COMPANY								
Proved Reserves	104,504	9,152	44,092	9,079	5,067	37,114	-	37,114
Proved Plus Probable Reserves	563,913	45,633	197,641	143,543	17,383	159,713	46,860	112,853

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	**Light and Medium Crude Oil (including solution gas and other by-products)**	10,151
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	19,203
Proved Plus Probable Reserves	**Light and Medium Crude Oil (including solution gas and other by-products)**	60,113
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	24,625

In the case of the United Kingdom after-tax net present values indicated in the foregoing tables, it should be noted that consolidations of after-tax cash flows for the total company Proved plus Probable case have been calculated by summation of the standalone cash flows for each individual property.

The UK regulations provide for the abandonment and reclamation cost of a field to be treated as a tax deductible expense, even though there may be no further income against which the cost may be offset. To the extent not required to offset income in the year of expenditure, this deductible expense can be carried back to prior years until the full cost is claimed against income. However, there is a limitation of 3 years' carry-back from the date of final cessation of production. Based on the price forecast assumptions reflected in the foregoing tables, the effect of this limitation on the Chestnut, Blane and Ettrick and Enoch fields is that the full abandonment and reclamation costs are not recoverable within the 3 year carry-back limitation period. Portions of these costs for these fields are therefore, in effect, not tax deductible expenses when the fields are evaluated on a standalone basis. This manifests itself as an apparent tax rate greater than 40% when the before-tax and after-tax cash flows are compared.

Therefore, depending upon corporate structuring, there may be an additional tax saving of £4.8 million (£2.9 million NPV 10%), arising from consolidation of the Proved plus Probable cash flows from all of the properties evaluated herein.

The constant benchmark reference product price and exchange rate assumptions reflected in the reserves data are summarized in Table 3.1. Forecast benchmark reference product price, inflation rate and exchange rate assumptions are summarized in Table 3.2. These forecast assumptions were provided in the Ryder Scott and APA Reports.

TABLE 3.1

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2003

CONSTANT PRICES AND COSTS

	OIL		NATURAL GAS		NATURAL GAS LIQUIDS				EXCHANGE RATE	
	EDMONTON PAR PRICE 40°API	BRENT	CANADA AECO GAS Price	U.K. GAS Price	FOB Field Gate ($Cdn/bbl)				CANADA	U.K.
YEAR	($Cdn/bbl)	($US/bbl)	($Cdn/MMBtu)	($Cdn/MMBtu)	CONDENSATE	BUTANE	PROPANE	ETHANE	($US/$Cdn)	(£/$Cdn)
CANADA										
2003 (Year End)	39.76	-	6.07	-	40.56	27.43	25.05	18.74	0.77	-
UNITED KINGDOM.										
2003 (Year End)	-	29.93	-	4.55	-	-	-	-	0.77	0.434

TABLE 3.2

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2003

FORECAST PRICES AND COSTS

YEAR	OIL: EDMONTON PAR PRICE 40ºAPI ($Cdn/bbl)	OIL: BRENT ($US/bbl)	NATURAL GAS: CANADA AECO GAS Price ($Cdn/MMBtu)	NATURAL GAS: U.K. GAS Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB Field Gate ($Cdn/bbl): CONDENSATE	BUTANE	PROPANE	ETHANE	INFLATION RATES (%/year)	EXCHANGE RATE: CANADA ($US/$Cdn)	EXCHANGE RATE: U.K. (£/$Cdn)
***CANADA*[(1)]**											
2004	33.11	-	5.83	-	33.77	22.84	20.86	17.98	-	0.72	-
2005	30.79	-	4.86	-	31.40	21.24	19.40	14.84	1.5	0.71	-
2006	31.26	-	4.93	-	31.88	21.57	19.69	15.07	1.5	0.70	-
2007	31.26	-	4.93	-	31.88	21.57	19.69	15.07	1.5	0.70	-
2008	31.26	-	5.01	-	31.88	21.57	19.69	15.32	1.5	0.70	-
Thereafter (Up to 2025)	~1.5%/yr (Beginning 2010)	-	~1.5%/yr	-	~1.5%/yr (Beginning 2010)	~1.5%/yr (Beginning 2010)	~1.5%/yr (Beginning 2010)	~1.6%/yr	1.5	0.70	-
***UNITED KINGDOM*[(2)]**											
2004	-	27.90	-	4.70	-	-	-	-	.75	0.763	0.433
2005	-	25.30	-	4.50	-	-	-	-	1.50	0.758	0.444
2006	-	23.70	-	4.20	-	-	-	-	1.50	0.752	0.442
2007	-	22.80	-	3.95	-	-	-	-	1.50	0.752	0.444
2008	-	22.20	-	3.59	-	-	-	-	1.50	0.741	0.439
Thereafter	-	21.40 (Beginning 2011)	-	3.46 (Beginning 2011)	-	-	-	-	1.50	0.741	0.439

(1) – from Ryder Scott Report
(2) – from APA Report

For the financial year ended December 31, 2003, the Company's weighted average prices received for oil, gas and by-products were as follows:

Weighted Average Price For:	**Canada**	**United Kingdom**
Crude Oil ($/bbl)	37.40	40.25
Natural Gas ($/mcf)	6.74	4.20
Condensate ($/bbl)	42.05	-
Pentanes + ($/bbl)	40.78	-
Butane ($/bbl)	25.13	-
Propane ($/bbl)	25.49	-
Ethane ($/bbl)	16.00	-

A reconciliation of changes to the Company's net proved, net probable and net proved plus probable reserves is provided in Table 4.1. This reconciliation reflects changes to the Company's reserves estimated using constant prices and costs.

A reconciliation of changes to the net present value of the Company's future net revenue discounted at 10 percent attributable to the Company's net proved reserves estimated using constant prices and costs is provided in Table 4.2.

TABLE 4.1

RECONCILIATION OF
COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE

CONSTANT PRICES AND COSTS

	LIGHT AND MEDIUM OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**	**Net Proved (MMcf)**	**Net Probable (MMcf)**	**Net Proved Plus Probable (MMcf)**
CANADA						
December 31, 2002	42.8	3.4	46.2	7,644	1,938	9,582
Extensions	-	-	-	2,152	474	2,626
Improved Recovery	-	-	-	-	-	-
Technical Revisions	0.8	9.1	9.9	(3,195)	(361)	(3,556)
Discoveries	-	-	-	1,814	304	2,118
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	(82)	-	(82)
Production	(14.4)	-	(14.4)	(1,987)	-	(1,987)
December 31, 2003	29.2	12.5	41.7	6,346	2,355	8,701
UNITED KINGDOM						
December 31, 2002	1,980.0	12,600.0	14,580.0	9,330	20,250	29,580
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(730.0)	(2,000.0)	(2,730.0)	(1,060)	(2,260)	(3,320)
Discoveries	-	-	-	-	-	-
Acquisitions	610.0	630.0	1,240.0	380	510	890
Dispositions	-	-	-	-	-	-
Economic Factors	(660.0)	580.0	(80.0)	40	(4,100)	(4,060)
Production	(370.0)	-	(370.0)	(1,420)	-	(1,420)
December 31, 2003	830.0	11,810.0	12,640.0	7,270	14,400	21,670

TABLE 4.2

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR

PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	**(M$)**
CANADA	
Estimated Future Net Revenue at December 31, 2002 (NPV After Tax)	26,632
Sales and Transfers of Oil and Gas, Net of Production Costs and Royalties	(12,352)
Net Change in Prices, Production Costs and Royalties Related to Future (Forecast) Production	(1,091)
Changes in Previously Estimated Development Costs Incurred During the Period	(485)
Changes in Estimated Future (Forecast) Development Costs	(898)
Extensions and Improved Recovery	5,784
Discoveries	8,203
Acquisitions of Reserves	-
Dispositions of Reserves	-
Net Change Resulting from (Technical Reserves) Revisions Plus All Other Changes	(9,586)
Accretion of Discount	3,125
Net Change in Income Taxes	4,617
Estimated Future Net Revenue at December 31, 2003 (NPV After Tax)	23,949
UNITED KINGDOM	
Estimated Future Net Revenue at December 31, 2002 (NPV After Tax)	37,700
Sales and Transfers of Oil and Gas, Net of Production Costs and Royalties	(12,400)
Net Change in Prices, Production Costs and Royalties Related to Future (Forecast) Production	4,500
Changes in Previously Estimated Development Costs Incurred During the Period	2,700
Changes in Estimated Future (Forecast) Development Costs	10,500
Extensions and Improved Recovery	-
Discoveries	-
Acquisitions of Reserves	5,600
Dispositions of Reserves	-
Net Change Resulting from (Technical Reserves) Revisions Plus All Other Changes	(42,800)
Accretion of Discount	600
Net Change in Income Taxes	9,400
Estimated Future Net Revenue at December 31, 2003 (NPV After Tax)	15,800

Undeveloped Reserves

All of the Company's undeveloped reserves are currently attributed to its UK properties and the vast majority of these reserves were originally booked prior to 1999. Most of these reserves are designated within the undeveloped category (either proved or probable) because relatively significant capital expenditures will be required in order to render these reserves capable of production.

Plans for future development of these undeveloped reserves are summarized below:

Kyle (Proved) –

> The APA Report assigns 540 mbbl oil and 4,410 mmcf gas as estimated proved undeveloped reserves in the Kyle field. Of these volumes, 140 mbbl oil and 2,830 mmcf gas are estimated to be in the Breccia gas cap. The remainder is the estimate of proved undeveloped reserves arising from a plan to divert Kyle production to the Banff field production facility. It is anticipated that a well will be drilled and the Breccia gas tied in to the Kyle gathering system in 2006 when sufficient ullage exists in the system.

Kyle, Chestnut, Blane, Ettrick and Enoch (Probable) –

> The APA report estimates 11,800 mbbl oil and 14,400 mmcf gas as probable reserves from all of the UK fields. Of these volumes, 660 mbbl oil and 4,910 mmcf gas are estimated to be in the Kyle field and are expected to be developed with the plans outlined for the proved reserves, as above. The remaining estimated probable volumes are in the Chestnut, Blane, Ettrick and Enoch fields.
>
> Timing of development depends on several factors but the most important – aligned partner interests coupled with an operator who wants to see them developed – is now falling into place. It is expected that the Blane field will be developed and on stream by late 2006/early 2007. Enoch development should follow close behind. The Chestnut field could proceed sooner than that with a standalone development. However, field economics are strongly influenced by the method of development and would likely improve through a tieback to existing infrastructure which does not seem possible until 2008/2009. The major participant and operator of the Ettrick field is now Encana Corporation. It is expected that Encana will plan and schedule the development of Ettrick along with Buzzard field development in the most commercial way, with production commencing sometime in the 2008 – 2010 timeframe.

Future Development Costs

A summary of the estimated development costs deducted in the estimation of future net revenue attributable to various reserves categories and prepared under various price and cost assumptions are summarized in the following table.

TABLE 5.3

SUMMARY OF ESTIMATED DEVELOPMENT COSTS ATTRIBUTABLE TO RESERVES

	ESTIMATED DEVELOPMENT COSTS (M$)		
	TOTAL PROVED		TOTAL PROVED PLUS PROBABLE
	CONSTANT PRICES & COSTS	FORECAST PRICES & COSTS	FORECAST PRICES & COSTS
CANADA			
2004	919	919	959
2005	-	-	24
2006	-	-	-
2007	-	-	-
2008	-	-	-
TOTAL (All Years):			
- UNDISCOUNTED	919	919	983
- DISCOUNTED @ 10%	876	876	935
UNITED KINGDOM			
2004	2,220	2,240	5,140
2005	1,130	1,140	5,420
2006	4,680	4,780	50,590
2007	-	-	3,080
2008	-	-	68,790
TOTAL (All Years):			
- UNDISCOUNTED	8,030	8,160	142,560
- DISCOUNTED @ 10%	6,780	6,890	102,120

The Company expects to fund its estimated future development costs from various sources including internally generated cash flow, equity or debt financing, or the possible sale of existing assets owned by the Company. Costs related to securing funding from the sale of equity or assets are anticipated to be up to 5 percent and the costs from borrowing against bank debt facilities are expected to be approximately 5 percent per annum on outstanding amounts. The effect of these costs of funding on the Company's reserves and future net revenue is not expected to be material relative to the incremental revenue stream generated.

Significant Factors or Uncertainties

Aside from the potential impact of material fluctuations in commodity prices, other significant factors or uncertainties that may affect either the Company's reserves or the future net revenue associated with such reserves include:

Canada –

- Certain newly drilled or developed properties such as those at Mirage and Rosevear may be considered less predictable insofar as estimating reserves and future net revenue are concerned until more historical production performance data is available.

- Most of the Company's Canadian natural gas is gathered, processed and compressed through facilities controlled by third parties on an interruptible basis. As such, the potential for curtailment of production volumes or significant fee increases does exist.

- Material changes to existing taxation or royalty rates and/or regulations.

United Kingdom –

- Field development costs and subsequent operating costs will be determined to some extent by available infrastructure in the area of the undeveloped field and the size and productive capacity of each well. Standalone solutions such as FPSOs require less capital but have high day-rates necessitating quick depletion of the reservoir. The ultimate reserves recovery is generally lower using an FPSO than for a development tied back to fixed production facilities.

- Fiscal terms - In the UK offshore the fiscal terms have been quite stable for a number of years except for the implementation of a supplementary charge in 2002 that effectively increased corporate tax from 30 percent to 40 percent and is offset to some extent by improved capital allowance rates.

Oil and Gas Properties and Wells

The following discussion outlines the Company's important properties, plants, facilities and installations:

Canada -

- Mirage Property, Alberta – the Mirage property is located approximately 420 km NW of Edmonton, Alberta. Natural gas is produced from multiple zones to a depth of 2400 m. The Company owns various working interests in 11 wells (5.9 net) in the area, seven of which produced approximately 7 mmcf/d (3.1 net) of natural gas and minor natural gas liquids at year-end. The Company also owned an interest in two field compressor stations in the area and operated nine wells and one compressor station at year-end 2003. Raw gas is gathered and processed through Duke Energy Midstream's East Gordondale facility.

- Highvale Property, Alberta – the Highvale property is located approximately 50 km west of Edmonton, Alberta. Natural gas is produced from multiple zones to a depth of 1500 m. The Company owns various working interest in 11 wells (8.0 net) in the area, five of which produced approximately 2 mmcf/d (1.4 net) of natural gas and 195 bbl/d (125 net) of natural gas liquids at year-end. All of these wells are operated by the Company. The Company owns and operates two field compressor stations in the area as well as two field booster compressors. Raw gas is gathered, compressed and either sold into ATCO's pipeline system or processed through third party-owned facilities in the area.

- Gilby Property, Alberta – the Gilby property is located approximately 120 km SW of Edmonton, Alberta. Natural gas is produced from multiple zones to a depth of 2400 m. The Company owns various working interests in eight wells (5.9 net) in the area, which together produced approximately 3.5 mmcf/d (1.2 net) of natural gas and 90 bbl/d (30 net) of natural gas liquids at year-end. Six of these wells are operated by the Company. Raw gas is gathered, compressed and processed through a variety of third party-owned facilities in the area.

- Rosevear Property, Alberta – the Rosevear property is located approximately 170 km west of Edmonton, Alberta. Natural gas is produced from multiple zones to a depth of 2400 m. The Company owns a 100 percent working interest in and operates two gas wells in the area, one of which produced approximately 1 mmcf/d of natural gas and minor natural gas liquids at year-end. Raw gas from this well is gathered, compressed and processed through third party-owned facilities in the area. The second gas well is slated for tie-in and production in 2004.

United Kingdom -

- Kyle Property, North Sea – Kyle is the Company's only producing property in the UK. It consists of four wells: three producing from the Cretaceous Chalk and the other from the Paleocene Sand, and a subsea pipeline complete with control umbilical for production through the Mearsk Curlew FPSO. A second subsea pipeline owned by Kyle owners provides a potential alternative to produce Kyle through the Banff Ramform.

- Chestnut Property, North Sea – Chestnut has one suspended well capable of production. The well was drilled in 2001 as an appraisal/development well and an extended well test was conducted at rates of up to 13,500 bopd over a five month period. The field is a candidate for standalone (FPSO) development or subsea tieback to existing infrastructure when sufficient ullage occurs.

- Blane, Ettrick and Enoch Properties, North Sea – A discussion of these undeveloped properties is included in the *Undeveloped Reserves* section of this statement. It should be noted that exploratory and appraisal wells have already been drilled into all of these fields to evaluate reserves size and productivity. All of these wells, with the exception of four wells as discussed under the *Abandonment and Reclamation Costs* section, have been abandoned following testing and therefore are not included in the well count for the United Kingdom summarized below.

The following table summarizes the number of oil and gas wells that the Company has a working interest in:

	Oil Wells		**Natural Gas Wells**	
	Gross	**Net**	**Gross**	**Net**
Alberta, Canada				
Producing	13	4.8	42	20.0
Non-producing	11	4.0	11	9.8
Saskatchewan, Canada				
Producing	7	0.1	0	0
Non-producing	0	0	0	0
United Kingdom				
Producing	4	0.57	0	0
Non-producing	1	0.15	0	0

Costs Incurred

For the year ended December 31, 2003, the Company incurred costs related to its acquisition, exploration and development activities as outlined in the following table.

	Costs Incurred (M$)	
	Canada	**United Kingdom**
Property Acquisition Costs:		
Proved Properties	203	(1,148)
Unproved Properties	1,234	1,182
Exploration Costs	10,686	8,926
Development Costs	5,448	16

Exploration and Development Activities

The Company's drilling activity and results for the year ended December 31, 2003 are summarized in the following table. It should be noted that the data outlined in this table reflects those wells that the Company participated in and that were rig-released during the period.

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Canada				
Oil Wells	0	0	0	0
Gas Wells	7	5.7	5	3.4
Service Wells	0	0	0	0
Suspended Wells	1	0.5	1	0.7
Abandoned Wells	8	4.6	0	0
Total Wells	16	10.8	6	4.1
United Kingdom				
Oil Wells	0	0	0	0
Gas Wells	0	0	0	0
Service Wells	0	0	0	0
Suspended Wells	0	0	0	0
Abandoned Wells	2	0.374	0	0
Total Wells	2	0.374	0	0

The Company's important exploration and development activities are summarized as follows:

Canada -

The Company's exploration and development activities are primarily concentrated in a corridor extending from south-central Alberta, through west-central Alberta and trending northwesterly into the "Peace River Arch area" of Alberta and northeast British Columbia. This corridor is predominantly a natural gas fairway, provides multi-zone potential, moderate drill depths, longer life reserves, and has available land and accessible infrastructure. The type of exploration and development opportunities present in the fairway are well suited to Bow Valley's experience base and skill sets.

The Company participates in a combination of full-cycle exploration and reduced-cycle exploration (farm-ins and joint ventures). Full-cycle exploration entails development of a prospect or drillable location through geological mapping, application of appropriate geophysical techniques and integration of engineering data. It also requires the subsequent acquisition of the mineral rights prior to drilling. In reduced-cycle exploration, the company is able to access other operator's lands and, often, their geological and geophysical data in order to assess and potentially commit capital to a prospect in a much shorter time frame than traditional full-cycle exploration.

In the Mirage area of Alberta, the Company was able to carry out a successful 2003 program that was comprised of a combination of full-cycle and reduced-cycle exploration and development. An initial discovery well was drilled during the first quarter of 2003 targeting a shallow Dunvegan reservoir. Subsequently, six follow-up shallow tests and two deeper tests were drilled through farm-ins and on earned lands over the course of 2003. Additional development and extension drilling is anticipated during 2004.

During 2003, the Company participated in drilling/re-entering 22 (14.9 net) wells and anticipates carrying out a similar level of activity in 2004.

United Kingdom -

The Company has concentrated its exploration activities in an area near the recently discovered Buzzard Field in the UK Central North Sea (CNS). In addition to its undeveloped Ettrick Field, the Company has various working interests in four licences and six part blocks covering 160,000 gross acres.

During 2003, the Company participated in two exploration wells in the Ettrick area. Both of the wells were dry and abandoned. The Company also participated in a 3D acquisition programme covering about 450 square kilometers, which will be used to define other potential prospects in this key area. At year end, the Company was participating in a third exploration well in the gas basin of the UK Southern North Sea (SNS). The well was about halfway to its objective at that time and was finished during January. It did not encounter commercial hydrocarbons and was subsequently abandoned.

The Company made two applications to the 21st UK Offshore Licensing Round in 2003 but was unsuccessful in obtaining any new licences.

Development work was relatively light during 2003 as the operators of all five undeveloped properties divested their interests. Consequently, work was confined to technical review of Chestnut and Enoch Fields. With the change of operators the Company expects a much more vigorous approach to field development in 2004.

Properties with No Attributed Reserves

The Company's unproved properties, including those for which the Company expects its rights to explore, develop and exploit to expire within one year, are outlined in the following table.

	Canada	**United Kingdom**
Unproved Properties (Total Company):		
Gross Area (acres)	78,632	225,048
Net Area (acres)	45,171	40,505
Work Commitments	None	See Below
Unproved Properties expected to expire in 2004:		
Gross Area (acres)	3,840	-
Net Area (acres)	1,485	-
Work Commitments	None	None

In 2002, the Company was awarded Licence P.1047 covering Blocks 20/7b, 20/3c and 20/8 (in total, 115,500 acres in which Company holds a 25% interest). The work programme offered was a firm well, 3D seismic acquisition and two contingent wells. The firm well and 3D seismic have been fulfilled and evaluation is currently underway to determine whether prospects are evident that would merit drilling one or both of the contingent wells.

Forward Contracts

In the United Kingdom, the Company's Kyle field gas production is sold under a long term contract linked in duration to the transportation contract which is tied to the economic life of the field. Under this contract, gas is priced in accordance with the formula established when the contracts were negotiated that is indexed to gas and gasoil indices for the UK market and this price is reset annually.

Abandonment and Reclamation Costs

The Company estimates its abandonment and reclamation costs in the following manner:

Canada –

The vast majority of the Company's wells and properties in Canada are located within Alberta. In deriving estimates for abandonment and reclamation costs, the Company has generally used the methodology outlined by the Alberta Energy and Utilities Board (EUB) within its Interim Directive 2001-8. This method results in well abandonment estimates that are based upon individual well characteristics and location, and lease reclamation estimates that are based on geographic location. In the case of facilities, the type of facility is used to estimate a multiplier that is applied to determine the relevant facility abandonment and reclamation cost. To factor in actual field experience and judgment, the Company has adjusted the EUB-based abandonment and reclamation estimates, as outlined in ID 2001-8, upwards by 25 to 33 percent.

Using this above-described methodology, the Company's total undiscounted abandonment and reclamation costs in Canada, net of estimated salvage value, are estimated at $3.65 million ($2.36 million discounted at 10 percent). It is estimated that this amount should cover such costs for approximately 65 net wells plus similar costs for the Company's facilities and pipelines interests. The portion of this amount that was not deducted as abandonment and reclamation costs in estimating the future net revenue attributable to the Company's Canadian reserves in the Ryder Scott Report was $2.97 million undiscounted ($1.93 million discounted at 10%). The portion of the Company's total abandonment and reclamation costs in Canada expected to be paid in the next three financial years is estimated at $0.60 million (undiscounted).

United Kingdom –

Decommissioning and abandonment liabilities (D & C costs) are estimated and included along with development costs in determining the future net revenue from a development property. Once developed and producing, provision is made for accounting purposes for DD&A in each year through its producing life.

At present, Bow Valley has accumulated DD&A for Kyle field where the future D & C costs are estimated to be about £1.7mm net (un-escalated 2004 costs). In addition to actual wells and facilities at Kyle, there is one suspended well capable of production on Chestnut field, and four suspended wells in other fields in which the Company has interests.

APA has estimated abandonment costs in present day values for all of the Company's evaluated properties. The net amount of abandonment and reclamation costs is £6.0mm and has been fully deducted from net revenues calculated by APA except for costs attributed to the four presently suspended wells. The Company conservatively estimates that its share of the future abandonment of these wells in present value terms will be about £0.75mm. It is unlikely that any abandonment and reclamation costs will be incurred within the next three years.

Tax Horizon

The Company is not required to pay income taxes for its most recently completed financial year. Based on the Company's current tax pool coverage and the operating revenues forecast in the Ryder Scott and APA Reports, the Company does not expect to pay cash income taxes for at least the next five years in either Canada or the United Kingdom.

Production Estimates

Estimated production volumes derived from the first year (2004) of the cash flow forecasts prepared in conjunction with the Company's reserves data (and included in the Ryder Scott and APA Reports) are provided in the following table.

TABLE 6.8

SUMMARY OF PRODUCTION ESTIMATES FOR 2004

	ESTIMATED PRODUCTION – 2004		
	LIGHT AND MEDIUM OIL (Mbbl)	**NATURAL GAS (MMCF)**	**NATURAL LIQUIDS (Mbbl)**
***CANADA* (1)**			
Total Company	12.7	2,139	59.4
Significant Fields:			
- Mirage	-	809	3.7
- Highvale	-	359	35.7
- Gilby	-	353	9.5
- Rosevear	-	282	8.4
***UNITED KINGDOM* (2)**			
Total Company	200	1,515	-
Significant Fields:			
- Kyle	200	1,515	-

Notes:

(1) Canada – estimated production from first year of proved producing reserves (forecast prices and costs) case in Ryder Scott Report dated March 18, 2004.

(2) United Kingdom - estimated production from first year of proved producing reserves (forecast prices and costs) case in APA Report dated March 18, 2004.

Production History

The Company's historical production and netback data for period ended December 31, 2003 is presented in Tables 6.9A and 6.9B.

TABLE 6.9A

SUMMARY OF
2003 PRODUCTION AND NETBACKS

	LIGHT AND MEDIUM OIL				
	Q1	**Q2**	**Q3**	**Q4**	**Total Year**
CANADA					
Company share of daily production[1] (bbl/d - before deduction of royalties)	43	48	47	49	47
Average ($/bbl):					
Price Received	$ 46.88	$ 34.45	$ 34.39	$ 35.06	$ 37.40
Royalties Paid	$ 6.12	$ 5.99	$ 4.73	$ 4.78	$ 5.38
Production Costs	$ 18.59	$ 21.05	$ 25.90	$ 18.52	$ 21.05
Netback	$ 22.17	$ 7.41	$ 3.76	$ 11.76	$ 10.97
Company share of annual 2003 production (bbl - before deduction of royalties)					
Total					17,000
Important Fields (greater than 20% of Total):					
- Mikwan					8,800
- Stettler					6,200
UNITED KINGDOM					
Company share of daily production[1] (bbl/d - before deduction of royalties)	1,336	1,078	808	795	1,002
Average ($/bbl):					
Price Received	$ 44.83	$ 40.20	$ 36.56	$ 36.55	$ 40.25
Royalties Paid	$ 0.18	$ 0.09	$ 0.11	$ 0.11	$ 0.12
Production Costs	$ 20.79	$ 11.34	$ 39.93	$ 22.41	$ 22.47
Netback	$ 23.86	$ 28.77	$ (3.48)	$ 14.03	$ 17.66
Company share of annual 2003 sales (not production) (bbl - before deduction of royalties)					
Total					365,800
Important Fields (greater than 20% of Total):					
- Kyle					365,800

(1) Note that oil production volumes are only that portion of production sold during the indicated period.

TABLE 6.9B

SUMMARY OF
2003 PRODUCTION AND NETBACKS

	NATURAL GAS					NATURAL GAS LIQUIDS				
	Q1	**Q2**	**Q3**	**Q4**	**Total Year**	**Q1**	**Q2**	**Q3**	**Q4**	**Total Year**
CANADA										
Company share of daily production	11,347	5,945	4,841	6,714	7,193	468	184	257	208	279
(mcf/d or bbl/d - before deduction of royalties)										
Average ($/bbl or $/Mcf):										
Price Received	$ 7.67	$ 6.22	$ 5.83	$ 6.32	$ 6.74	$ 27.23	$ 24.12	$ 26.38	$ 21.31	$ 26.30
Royalties Paid	$ 1.00	$ 1.95	$ 1.79	$ 2.08	$ 1.58	$ 10.82	$ 3.92	$ 5.42	$ 16.44	$ 9.48
Production Costs	$ 0.66	$ 1.54	$ 1.64	$ 1.45	$ 1.19	---------------- Included in Natural Gas --------------				
Netback	$ 6.01	$ 2.73	$ 2.40	$ 2.79	$ 3.97	$ 16.41	$ 20.20	$ 20.96	$ 4.87	$ 16.82
Company share of annual 2003 production										
(mcf or bbl - before deduction of royalties)										
Total					2,625,300					101,700
Important Fields (greater than 20% of Total):										
- Balsam					537,200					7,200
- Gilby					689,100					137,900
- Highvale					691,400					184,900
UNITED KINGDOM										
Company share of daily production	3,894	4,140	4,359	3,210	3,900	0	0	0	0	0
(mcf/d or bbl/d - before deduction of royalties)										
Average ($/bbl or $/Mcf):										
Price Received	$ 4.40	$ 4.17	$ 4.10	$ 4.12	$ 4.20	$ -	$ -	$ -	$ -	$ -
Royalties Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Costs	----------- Included in Light & Med Oil -----------					$ -	$ -	$ -	$ -	$ -
Netback	$ 4.40	$ 4.17	$ 4.10	$ 4.12	$ 4.20	$ -	$ -	$ -	$ -	$ -
Company share of annual 2003 production										
(mcf or bbl - before deduction of royalties)										
Total					1,423,600					0
Important Fields (greater than 20% of Total):										
- Kyle					1,423,600					0

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
1200, 530 - 8TH AVENUE S.W. CALGARY, ALBERTA T2P 3S8 FAX (403) 262-2790 TELEPHONE (403) 262-2799

March 18, 2004

The Board of Directors
Bow Valley Energy Ltd.
1200, 333 – 7th Avenue S.W.
Calgary, Alberta
T2P 2Z1

Re: **Form 51-101 F2 Report on Reserves Data by Independent Qualified Reserves Evaluator**

1. We have evaluated Bow Valley Energy Ltd.'s (the Company's) reserves as at December 31, 2003. The reserves data consist of the following:

   a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

      (ii) the related estimated future net revenue; and

   b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

      (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (Cdn 000"s)
Ryder-Scott Company	Estimates of Reserves and Future Income from Certain Leasehold and Royalty Interests of Bow Valley Energy Ltd. March 18, 2004	Canada	$24,698

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Ryder Scott Company-Canada, Calgary, Alberta, Canada

Signed by: Andrew J. Thompson, P.Eng.

Title: Vice President, Manager-Calgary Office

PETROLEUM APA ENGINEERING

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APR - 7 2004

March 18, 2004

The Board of Directors,
Bow Valley Energy Ltd.
1205, 333 – 7 Avenue S.W.
Calgary, Alberta
T2P 2Z1

Subject: Form 51-101F2, Report on Reserves Data

1. We have evaluated the reserves data of Bow Valley Energy Ltd. (the "Company") as at December 31, 2003. The reserves data consist of the following:

   (a) (i) Proved and Proved plus Probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and
   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator	Description of Evaluation Report	Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue[1] Before Income Taxes Proved + Probable Reserves Million Canadian Dollars, 10% discount rate		
				Audited	Evaluated	Reviewed
APA Petroleum Engineering Inc	"Reserves Evaluation North Sea Assets of Bow Valley Energy Limited, as of December 31, 2003 "	March 18, 2003	United Kingdom	$ n/a-	$ 60.04	$ n/a

(1) Future net revenue as defined by "Companion Policy 51-101CP, Standards of Disclosure for Oil and Gas Activities, Appendix 1"

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

APA Petroleum Engineering Inc,

Brian D. Weatherill, P.Eng.

FORM 51-101F3

REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

BOW VALLEY ENERGY LTD.

Management of Bow Valley Energy Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

(ii) the related estimated future net revenue.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The reports of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information:

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed)
Robert G. Moffat,
President & CEO

(signed)
David A. Fleming. P.Eng.
Vice President, International

(signed)
John W. Essex, P. Eng.
Vice President, Operations

(signed)
Kenneth R. Stiles, Director

(signed)
Henry R. Lawrie, Director

April 22, 2004