

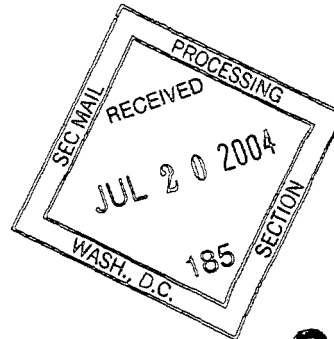
**APF Energy Trust
Form 51-102 F4
Business Acquisition Report**



04035692

Item 1 Identity of Company
1.1 Name and Address of Company

APF Energy Trust (the "Trust")
2100, 144 - 4th Avenue S.W.
Calgary, Alberta
T2P 3N4

**SUPPL**

1.2 Executive Officer

For further information contact Steven Cloutier, President of APF Energy Inc. by telephone at (403) 294-1000 or by fax at (403) 294-1074.

Item 2 Details of Acquisition

2.1 Nature of Business Acquired

Pursuant to the offer by APF Energy Inc. and the Trust to acquire all of the issued and outstanding common shares (the "Shares") of Great Northern Exploration Ltd. ("Great Northern") dated April 26, 2004 (the "Offer"), 41,694,977 Shares, representing approximately 95% of the Shares were acquired pursuant to the Offer.

Holders of the Shares were entitled to elect, for each Share, 0.414614 of a trust unit of the Trust ("Units") or \$5.05 in cash, subject to an aggregate maximum of \$55,190,101.65 and proration.

A total of 33,053,803 Shares were tendered for cash, while 6,509,874 Shares were tendered for Units. As a result, those Great Northern shareholders electing to receive cash for all, or a portion, of their holdings received \$1.573252 per Share, with the balance being satisfied by the issuance of Units on the basis of 0.285447 Units per Share. There was no proration for those Great Northern shareholders who elected to receive all Units. A total of 2,131,300 Shares were also purchased by APF Energy Inc. in the open market.

APF acquired all remaining Shares of Great Northern by way of a compulsory acquisition transaction pursuant to the *Business Corporations Act* (Alberta).

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APF Energy Inc., Great Northern and a wholly-owned subsidiary of Great Northern were amalgamated on June 9, 2004 and the amalgamated company is named "APF Energy Inc.".

Great Northern was a publicly traded junior oil and gas company listed on the Toronto Stock Exchange, with revenues derived primarily from oil and gas properties in Alberta and Saskatchewan. Great Northern's operations were primarily concentrated in the areas of Great Provost in East Central Alberta, the Robsart area of Southwest Saskatchewan and in the West Central Alberta area.

Based on Great Northern's reserve report effective December 31, 2003, Great Northern's total proved reserves were 11,781 thousand barrels of oil equivalent ("mboe"), and proved plus probable reserves were 17,074 mboe, in each case using forecast prices and costs.

2.2 Date of Acquisition

June 4, 2004

2.3 Consideration

As set forth in item 2.1, consideration for the acquisition of the Shares of Great Northern was a combination of a maximum of \$55 million in cash and Units. A maximum of 12,712,645 Units may be issued, if all holders of Shares that will be acquired on the compulsory acquisition, elect Units. Aggregate consideration for the transaction was \$285 million (before transaction costs), which includes the assumption of \$65 million of debt of Great Northern.

2.4 Effect on Financial Position

On completion of the acquisition of Great Northern, APF Energy Inc., Great Northern and 905698 Alberta Ltd., a wholly-owned subsidiary of Great Northern, were amalgamated to form "APF Energy Inc.". It is estimated that the combined entity will have 2004 average annual production of 15,850 boe/day, based on 12 months of production of APF Energy and on seven months of production of Great Northern.¹

A summary of the estimated effects of the acquisition of Great Northern on the Trust and the information presented in the Trust's *Statement of Reserves Data and Other Oil and Gas Information* on Form 51-101F1 contained in the Trust's annual information form for the year ended December 31, 2003 is set forth below.

¹ "boes" as used in this document may be misleading, particularly if used in isolation. A boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves Data

The oil and natural gas reserves of APF Energy Inc. ("APF") and APF Energy Limited Partnership ("APF Partnership") were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ") effective January 1, 2004. The coalbed methane reserves of Tika Energy Inc. ("Tika"), a wholly owned subsidiary of APF were evaluated by McDaniel & Associates Consultants Ltd. and were consolidated with the GLJ evaluated properties to generate corporate total forecasts. The oil and natural gas reserves of Great Northern were evaluated by GLJ effective December 31, 2003.

Following is a summary of the oil and natural gas reserves and the value of future net revenues of APF, APF Partnership, Tika and Great Northern as evaluated by GLJ (except with respect to Tika, as noted above). The pricing used in the forecast and constant price evaluations is also set forth below.

It should not be assumed that the estimated present worth values of net production revenue contained in the following tables represents the fair market value of the reserves. All evaluations have been stated prior to any provision for income taxes. There is no assurance that the price and cost assumptions contained in the constant price and cost and escalating price and cost assumption cases will be attained and variances could be material.

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

CONSTANT PRICES AND COSTS

Reserves Category	Constant Reserves									
	Natural Gas		Light & Medium Oil		Heavy Oil		Natural Gas Liquids		Total	
	Gross (mmcf)	Net (mmcf)	Gross (mmbbl)	Net (mmbbl)	Gross (mmbbl)	Net (mmbbl)	Gross (mmbbl)	Net (mmbbl)	Gross (mboe)	Net (mboe)
Proved										
Developed Producing	95,681	79,224	16,138	14,313	1,069	998	1,694	1,239	34,848	29,755
Developed Non-Producing	10,464	8,314	912	849	668	633	339	262	3,662	3,131
Undeveloped	4,567	3,632	2,851	2,514	207	186	176	125	3,996	3,431
Total Proved	110,712	91,170	19,901	17,676	1,944	1,817	2,209	1,626	42,506	36,317
Probable	42,137	34,679	7,240	6,379	1,287	1,174	560	421	16,110	13,754
Total Proved plus Probable	152,849	125,849	27,141	24,055	3,231	2,991	2,769	2,047	58,616	50,071

Columns may not add due to rounding.

Reserves Category	NET PRESENT VALUE OF FUTURE NET REVENUE				
	BEFORE INCOME TAXES				
	DISCOUNTED AT (%/year)				
	0% (MMS)	5% (MMS)	10% (MMS)	15% (MMS)	20% (MMS)
Proved					
Developed Producing	664.0	523.7	438.3	380.5	338.5
Developed Non-Producing	74.5	51.5	40.5	33.9	29.4
Undeveloped	67.8	44.9	31.5	23.1	17.5
Total Proved	806.2	620.0	510.4	437.6	385.5
Probable	286.6	187.4	136.6	105.6	84.8
Total Proved plus Probable	1,092.9	807.4	646.9	543.2	470.2

Columns may not add due to rounding.

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003**

FORECAST PRICES AND COSTS

Reserves Category	Constant Reserves									
	Natural Gas		Light & Medium oil		Heavy Oil		Natural gas liquids		Total	
	Gross (mmcf)	Net (mmcf)	Gross (mmbbl)	Net (mmbbl)	Gross (mmbbl)	Net (mmbbl)	Gross (mmbbl)	Net (mmbbl)	Gross (mboe)	Net (mboe)
Proved										
Developed Producing	94,437	78,158	15,406	13,685	978	919	1,670	1,225	33,793	28,855
Developed Non-Producing	10,481	8,312	923	860	624	592	341	264	3,634	3,101
Undeveloped	4,658	3,684	2,824	2,559	201	181	176	127	3,976	3,481
Total Proved	109,576	90,154	19,153	17,104	1,803	1,692	2,187	1,616	41,403	35,437
Probable	41,286	33,979	6,999	6,199	1,205	1,105	557	420	15,643	13,387
Total Proved plus Probable	150,862	124,133	26,152	23,303	3,008	2,797	2,744	2,036	57,046	48,824

Columns may not add due to rounding.

Reserves Category	NET PRESENT VALUE OF FUTURE NET REVENUE				
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
	0% (MMS)	5% (MMS)	10% (MMS)	15% (MMS)	20% (MMS)
Proved					
Developed Producing	465.2	385.9	333.0	295.2	266.8
Developed Non-Producing	56.5	39.1	31.1	26.3	23.0
Undeveloped	44.3	28.5	19.1	13.4	9.4
Total Proved	565.9	453.5	383.2	334.9	299.2
Probable	196.1	128.4	93.3	71.6	57.0
Total Proved plus Probable	762.0	581.9	476.5	406.4	356.2

Columns may not add due to rounding.

Notes:

- (1) The net present value of future net revenues has been presented only on a before income taxes basis. Given the structure of the Trust, the values after income taxes would be the same.
- (2) "Gross" reserves are the company working interest share before deduction of royalties and without including royalty interests.
- (3) "Net" reserves are the company working interest share after deduction of royalty obligations, plus royalty interests.
- (4) ARTCs associated with eligible interests have been included.
- (5) The effect on projected revenues from hedging activity has not been included.
- (6) Processing income was included as "Other Income" in the corporate total economic forecast.
- (7) Provisions for the abandonment and reclamation of only those company wells assigned reserves by GLJ were included.
- (8) General and administrative costs and overhead recovery were not included.
- (9) The constant price analysis was performed by rerunning the evaluation database using fixed last day (December 31, 2003) posted pricing and no cost escalations.
- (10) Subsequent to December 31, 2003, Great Northern acquired producing properties for \$23 million, complimentary to its existing Innisfail area, information relating to which was disclosed in a press release of Great Northern dated February 2, 2004. Reserves values for Great Northern summarized in the press release of the Trust dated April 7, 2004 announcing the Offer, included the acquisition made by Great Northern in February, 2004. The reserves and net revenue from reserves from such acquisition are not included in the tables above.
- (11) "mmcf" means million cubic feet; "mmbbl" means thousand barrels.

**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\$)	WELL ABANDONMENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Reserves	1,548,896	247,472	425,822	32,420	36,892	806,291	46,406	759,885
Proved Plus Probable Reserves	2,114,972	343,299	565,143	74,559	39,091	1,092,879	85,140	1,007,739

**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)	217,906
	Heavy Oil (including solution gas and other by-products)	18,614
	Natural Gas (including by-products but excluding solution gas from oil wells)	270,785
	Coalbed Methane	3,080
Total Proved		510,385
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	279,351
	Heavy Oil (including solution gas and other by-products)	27,862
	Natural Gas (including by-products but excluding solution gas from oil wells)	335,711
	Coalbed Methane	4,030
Total Proved plus Probable		646,954

**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\$)	WELL ABANDONMENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Reserves	1,297,800	201,004	452,084	33,508	45,232	565,972	24,599	541,374
Proved Plus Probable Reserves	1,773,256	277,267	608,928	76,134	48,938	761,990	50,103	711,888

**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) Heavy Oil (including solution gas and other by-products) Natural Gas (including by-products but excluding solution gas from oil wells) Coalbed Methane	149,365 13,536 218,183 2,191
Total Proved		383,275
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products) Heavy Oil (including solution gas and other by-products) Natural Gas (including by-products but excluding solution gas from oil wells) Coalbed Methane	191,357 20,808 261,225 3,079
Total Probable		476,470

Pricing Assumptions

The following tables set forth the benchmark reference prices and pricing assumptions used in preparing the reserves data and, in the case of forecast prices and costs, the inflation rate assumptions.

**SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2003**

CONSTANT PRICES AND COSTS

Crude Oil and Natural Gas Prices

Year	Inflation %	Exchange Rate US\$/SCdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current US\$/bbl	Brent Blend Crude Oil FOB North Sea Then Current US\$/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current SCdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current SCdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current SCdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current SCdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars)			
									Spec Ethane SCdn/bbl	Edmonton Propane SCdn/bbl	Edmonton Butane SCdn/bbl	Edmonton Pentanes Plus SCdn/bbl
2003 (Year End)	0.0	0.7738	32.52	31.02	40.81	29.81	23.31	34.81	19.50	29.81	31.81	41.31

Constant Thereafter

Natural Gas and Sulphur

Year	US Gulf Coast Gas Price @ Henry Hub Then Current \$/mmBtu	Midwest Price @ Chicago Then Current \$/mmBtu	AECO-C Spot Then Current \$/mmBtu	Alberta Plant Gate				Saskatchewan Plant Gate			British Columbia		Sulphur FOB Vancouver \$/LT	Alberta Sulphur at Plant Gate \$/LT
				Spot Then Current \$/mmBtu	ARP \$/mmBtu	Aggregator \$/mmBtu	Alliance \$/mmBtu	SaskEnergy \$/mmBtu	Spot \$/mmBtu	Sumas Spot \$/mmBtu	CanWest Plant Gate \$/mmBtu	Spot Plant Gate \$/mmBtu		
2003 (Year End)	5.77	5.86	6.09	5.83	5.73	5.43	5.83	5.88	5.98	5.49	5.43	5.78	59.50	35.00

Constant Thereafter

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.

The plant gate price represents the price before raw gas gathering and processing changes are deducted.

Spot refers to weighed average one month price.

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

FORECAST PRICES AND COSTS

Year	OIL ⁽¹⁾				Natural Gas ⁽¹⁾ AECO Gas Price (\$/mmBtu)	Edmonton Pentanes Plus (\$/mmBtu)	Inflation Rates ⁽¹⁾ (%/Year)	Exchange Rate ⁽²⁾ (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$/bbl)	Edmonton Par Price 40° API (\$/bbl)	Hardisty Heavy 12° API (\$/bbl)	Cromer Medium 29.3° API (\$/bbl)				
Forecast								
2004	29.00	37.75	20.25	31.75	5.85	38.25	1.5	0.75
2005	26.00	33.75	20.25	28.75	5.15	34.25	1.5	0.75
2006	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
2007	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
2008	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
2009-2014	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
Thereafter	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	1.5	0.75

Notes:

- (1) Inflation rates for forecasting prices and costs.
- (2) Exchange rates used to generate the benchmark reference prices in this table.
- (3) The price forecast is the GLJ standard price forecast effective January 1, 2004.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, undeveloped reserves are scheduled to be developed within the next two years of the effective date. Capital expenditures to develop proved undeveloped reserves are estimated at \$14.511 million in 2004 and \$4.680 million in 2005.

Properties with no Attributed Reserves

Great Northern had undeveloped land holdings at December 31, 2003 of 374,914 gross acres (140,995 net). Rights to explore and develop approximately 48,000 net acres are expected to expire by December 31, 2004.

Oil and Gas Wells

The acquisition of Great Northern increases the number of wells in which APF has an interest as follows: oil wells – 229 gross producing (111 net); 233 gross shut-in (133 net); natural gas wells – 270 gross producing (97 net) and 227 gross shut-in (73 net), as at December 31, 2003.

Significant Factors or Uncertainties

There are no significant factors or uncertainties that may impact the reserves and values arising from the acquisition of Great Northern, other than the risks inherent in the oil and gas industry generally, the risks associated with the Trust's corporate and other acquisitions and other risks as identified in the Trust's annual information form for the year ended December 31, 2003.

Future Development Costs

The following table sets forth development costs deducted in the estimation of future net revenue attributable to the reserve categories noted below.

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

Reserves Category	Development Costs Deducted in Estimating Future Net Revenues													
	Development Costs – Undiscounted (\$000)							Development Costs - 10% Discount Rate						
	2004	2005	2006	2007	2008	Thereafter	Total	2004	2005	2006	2007	2008	Thereafter	Total
Total Proved (Constant prices and costs)	18,322	5,000	3,569	626	901	4,002	32,423	17,469	4,334	2,812	448	587	1,650	27,301
Total Proved (Forecast prices and costs)	18,327	5,127	3,679	655	953	4,767	33,507	17,474	4,444	2,899	469	620	1,850	27,757
Total Proved plus Probable (Forecast prices and costs)	43,154	15,766	7,664	2,621	1,233	5,696	76,134	41,146	13,666	6,039	1,878	803	2,181	65,712

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment and reclamation costs, based on actual costs incurred to date for abandonment and reclamation activities, for the next three years are \$2.06 million in 2004, \$1.51 million in 2005 and \$1.61 million in 2006.

Tax Horizon

As a result of the Trust's tax efficient structure, annual taxable income is transferred from its operating entities to the Trust, and from the Trust to its unitholders. This is primarily accomplished through the deduction of the royalties on underlying oil and gas properties held by

the Trust's operating subsidiaries. Therefore, it can be expected that no income tax liability will be incurred by the Trust for as long as the organization maintains this corporate tax structure.

Production Estimates

The following table sets out the gross volume of estimated production for the year ended December 31, 2004, from the Total Proved Reserves based on constant prices and costs.

	Light and Medium Crude Oil bbl/d	Heavy Oil bbl/d	Natural Gas mcf/d	NGLs bbl/d	Boe boe/d
Total Proved	6,646	1,107	57,338	941	18,251

Note:

(1) The above estimated production reflects 12 months of production for both APF and Great Northern.

2.5 Prior Valuations

None.

2.6 Parties to Transaction

Not applicable.

2.7 Date of Report

June 29, 2004.

Item 3 Financial Statements

The unaudited pro forma consolidated financial statements of the Trust are attached as Schedule A hereto. The audited annual consolidated financial statements of Great Northern for the years ended December 31, 2003 and 2002 are attached as Schedule B hereto. The unaudited consolidated interim financial statements of Great Northern for the three month periods ended March 31, 2004 and 2003 are attached as Schedule C hereto.

SCHEDULE A

PRO-FORMA CONSOLIDATED FINANCIAL STATEMENTS THREE MONTHS ENDED MARCH 31, 2004

Compilation Report

**To the Trustee of APF Energy Trust
and to the Directors of APF Energy Inc.**

We have read the accompanying unaudited pro-forma consolidated balance sheet as at March 31, 2004 and the unaudited pro-forma statement of operations of APF Energy Trust (the "Trust") for the three months ended March 31, 2004, and have performed the following procedures.

1. Compared the figures in the columns captioned "APF Energy Trust" and "Great Northern Exploration Ltd." to the unaudited financial statements of the applicable entity as at or for the three months ended March 31, 2004, and found them to be in agreement.
2. Made inquiries of certain officials of the Trust who have responsibility for financial and accounting matters about:
 - (a) the basis for determination of the pro-forma adjustments; and
 - (b) whether the pro-forma financial statements comply as to form in all material respects with *Securities Acts* of the various Provinces of Canada (the "Acts").

The officials:

- (a) described to us the basis for determination of the pro-forma adjustments, and
 - (b) stated that the pro-forma statements comply as to form in all material respects with the Acts.
3. Read the notes to the pro-forma statements, and found them to be consistent with the basis described to us for determination of the pro-forma adjustments.
4. Recalculated the application of the pro-forma adjustments to the aggregate of the amounts in the columns captioned "APF Energy Trust" and "Great Northern Exploration Ltd." as at and for the three months ended March 31, 2004 and found the amounts in the columns captioned "Total" to be arithmetically correct.

A pro-forma financial statement is based on management assumptions and adjustments which are inherently subjective. The foregoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with respect to management's assumptions, the pro-forma adjustments, and the application of the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro-forma financial statements, and we therefore make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

(Signed) "PricewaterhouseCoopers LLP"
Chartered Accountants

Calgary, Alberta
June 28, 2004

APF Energy Trust
Pro-Forma Consolidated Balance Sheet
(Unaudited)
March 31, 2004

2

	APF Energy Trust March 31, 2004	Great Northern Exploration Ltd. March 31, 2004	Adjustments (Note 2(a))	Total
	(\$000s)			
ASSETS				
Current assets				
Cash	739	—		739
Accounts receivable	28,498	11,473		39,971
Deferred derivative loss	1,178	—		1,178
Other current assets	3,703	546		4,249
	34,118	12,019		46,137
Asset retirement fund	2,693	—		2,693
Goodwill	48,230	—	78,655	126,885
Property, plant and equipment	409,923	160,448	118,436	688,807
	494,964	172,467	197,091	864,522
LIABILITIES				
Current liabilities				
Bank debt	—	45,596	(45,596)	—
Accounts payable and accrued liabilities	28,785	21,916		50,701
Derivative liabilities	4,443	—		4,443
Cash distribution payable	6,943	—		6,943
	40,171	67,512	(45,596)	62,087
Future income taxes	58,614	9,641	47,590	115,845
Long-term debt	55,000	—	127,705	182,705
Asset retirement obligations	22,187	7,866		30,053
	175,972	85,019	129,699	390,690
UNITHOLDERS' EQUITY				
Unitholders' investment account	386,003	72,859	81,981	540,843
Contributed surplus	1,325	251	(251)	1,325
Accumulated earnings	88,022	14,338	(14,338)	88,022
Accumulated cash distributions	(199,192)	—	—	(199,192)
Convertible debentures	46,277	—		46,277
Accumulated interest on convertible debentures	(3,443)	—		(3,443)
	318,992	87,448	67,392	473,832
	494,964	172,467	197,091	864,522

APF Energy Trust

3

Pro-Forma Consolidated Statement of Operations

(Unaudited)

March 31, 2004

	APF Energy Trust Three Months Ended March 31, 2004	Great Northern Exploration Ltd. Three Months Ended March 31, 2004	Adjustments (Note 2(b))	Total
(\$000s except per unit amounts)				
Revenue				
Oil and natural gas	46,355	19,529		65,884
Realized derivative loss – net	(1,027)			(1,027)
Non-cash derivate loss – net	(3,265)			(3,265)
Royalties expense, net of ARTC	(9,057)	(3,909)	(125) (vi)	(13,091)
Transportation	(865)	–		(865)
	32,141	15,620	(125)	47,636
Expenses				
Operating	8,910	3,892		12,802
General and administrative – net	1,839	304		2,143
Stock based compensation expense	257	–		257
Interest on long-term debt	977	538	1,026 (ii)	2,541
Capital and other taxes	605	–	201 (v)	806
Depletion, depreciation and accretion	17,033	5,591	3,131 (i)(iv)	25,755
	29,621	10,325	4,359	44,305
Income before income taxes	2,520	5,295	(4,484)	3,331
Provision for income taxes (recovery)				
Current	–	94	(94) (v)	–
Future	(5,607)	1,900	(1,713) (iii)	(5,420)
Net income for the period	8,127	3,301	(2,677)	8,751
Net income per unit – basic	0.19			0.15
Net income per unit – diluted	0.19			0.15

1. Basis of Presentation

The pro-forma consolidated financial statements of APF Energy Trust (the "Trust"), which owns a 99% interest in certain oil and gas royalties, have been prepared by management to give effect to the purchase of Great Northern Exploration Ltd. ("GNEL"). GNEL was involved in oil and gas exploration, development and production in western Canada. The pro-forma consolidated financial statements have been prepared from information derived from the March 31, 2004 unaudited consolidated historical financial statements of the Trust and the March 31, 2004 unaudited financial statements of GNEL, and the assumptions set out in note 2 below.

The GNEL Shares were purchased by the Trust through a take-over bid which closed June 4, 2004. The pro-forma consolidated statement of operations gives effect to those transactions as if they occurred January 1, 2004. The pro-forma consolidated balance sheet gives effect to those transactions at March 31, 2004.

The pro-forma consolidated financial statements do not give effect to any transaction that does not meet the significant test rules as defined by various securities regulators.

The pro-forma consolidated financial statements may not be indicative of the financial position or the results of operations or royalty distribution of the Trust which will be obtained upon completion of the acquisition of GNEL (the "Acquisition"). In preparing the pro-forma consolidated financial statements, no adjustments have been made to reflect any operating or administrative cost savings that may result from the operations of the consolidated assets.

Accounting policies used in the preparation of the pro-forma financial statements are in accordance with those disclosed in the Trust's unaudited financial statements as at and for the three months ended March 31, 2004. The acquisition of GNEL has been accounted for as a business acquisition. In the opinion of management, the pro-forma financial statements include all adjustments necessary for fair presentation.

The pro-forma statements should be read in conjunction with the Trust's unaudited consolidated financial statements as at and for the three months ended March 31, 2004 and the unaudited financial statements of GNEL for the three months ended March 31, 2004.

The Trust is an open-ended investment trust under the laws of the Province of Alberta.

The royalty interests (the "Royalty") in producing oil and natural gas properties acquired from APF Energy Inc. and APF Energy Limited Partnership (collectively "APF") effectively transfer 99% of the economic interest in such properties to the Unitholders. The Royalty constitutes a royalty interest in the oil and natural gas properties owned by APF but does not confer ownership in the underlying resource properties. APF is permitted to borrow funds to finance the purchase of additional properties and tangibles, for capital expenditures or for other financial obligations or encumbrances in respect of the properties should the properties not generate sufficient income to repay debt. The Trust is entitled to 99% of the production and incidental revenues from the properties less all costs and expenses in respect of the properties, taxes in respect of the properties, general and administrative costs of APF and the Royalty and debt service charges (including principal repayments). The Trust is required to reimburse APF for Crown royalties and charges in respect of production allocable to the Royalty.

2. Pro-forma adjustments and assumptions

- (a) The pro-forma consolidated balance sheet of the Trust as at March 31, 2004, has been prepared as if the following transactions had been completed as of the balance sheet date:

GNEL ACQUISITION

The purchase by the Trust of 100% of the shares of GNEL for \$227,292,000 before adjustments and other costs is assumed to be paid 25% in cash with the balance in Trust Units, and is accounted for as a business combination and is allocated as follows:

	(000s)
Property plant and equipment	\$278,884
Goodwill	78,655
Current assets	12,019
Current liabilities	(21,916)
Bank debt	(55,253)
Asset retirement obligations	(7,866)
Future income taxes	(57,231)
Net	<u>\$227,292</u>

Paid by:	
Trust Units (12,712,645 Trust Units)	154,840
Bank Indebtedness	65,353
Transaction costs including severance	<u>7,099</u>
	<u>\$227,292</u>

The current bank debt of GNEL has been reclassified to long term debt to be consistent with APF's credit facilities.

- (b) The pro-forma consolidated statement of operations has been prepared as if the proposed transactions took place on January 1, 2004.
- (i) The purchase price allocated to the GNEL assets are amortized on a unit of production basis;
 - (ii) the interest for the change of bank debt related to the Acquisition has been recorded at 5% per annum with no deemed principal repayments;
 - (iii) current taxes were adjusted to account for income taxes as if the income from the acquisitions subject to the royalty calculation was in effect January 1, 2004. The taxes on the incremental income are assumed to be passed to the Unitholders through the royalty calculation. The future income tax expense has been adjusted to reflect the impact on earnings of the transactions at the maximum statutory rate;
 - (iv) site restoration in the case of GNEL has been reclassified from depletion and amortization;
 - (v) a Saskatchewan surtax is applied to certain properties and capital taxes have been reclassified out of income taxes;
 - (vi) Alberta Royalty Tax Credit was adjusted to reduce the amount to the maximum allowable for the period;
 - (vii) the net income on a per unit basis is based on 50,093,245 Trust Units assumed outstanding for the period (54,410,228 diluted).

3. Unitholders' equity

The authorized unit capital of the Trust consists of 500,000,000 Trust Units of which 34,074,240 Trust Units were outstanding at December 31, 2003, with 4,765,000 Trust Units issued under the January 27, 2004 prospectus and the assumption that 12,712,645 Trust Units were issued to the shareholders of GNEL. Pursuant to a June 26, 2003 prospectus, the Trust sold 50,000, 9.40% Convertible Unsecured Subordinated Debentures at a price of \$1,000 per Debenture. The maturity date is July 31, 2008. The Debentures are convertible at the holder's option into fully paid Trust Units at a conversion price of \$11.25 per Trust Unit, being a conversion rate of 88.8889 Trust Units for each \$1,000 principal amount of Debentures. The Trust is also authorized to issue an unlimited number of Special Voting Units.

4. GNEL Acquisition

On April 6, 2004, APF Energy and GNEL entered into an agreement whereby APF Energy agreed to acquire GNEL at a price of \$5.05 per share, payable at the option of the GNEL shareholders in cash for a maximum of 25% of the Purchase Price, or in Trust Units of the Trust, based on an exchange ratio of 0.414614 Trust Units for each GNEL Share. On June 4, 2004, APF Energy took up all of the GNEL shares tendered to the offer to acquire all of the shares of GNEL.

The pro-forma consolidated statement of operations have been prepared based on the fact that the GNEL shareholders elected for the maximum cash.

**PRO-FORMA CONSOLIDATED FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2003**

Compilation Report

**To the Trustee of APF Energy Trust
and to the Directors of APF Energy Inc.**

We have read the accompanying unaudited pro-forma statement of operations of APF Energy Trust (the "Trust") for the year ended December 31, 2003, and have performed the following procedures.

1. Compared the figures in the columns captioned "APF Energy Trust" and "Great Northern Exploration Ltd." to the audited financial statements of the applicable entity as at or for the year ended December 31, 2003, and found them to be in agreement.
2. Compared the figures in the columns captioned "Hawk Oil Inc." and "Nycan Energy Corp." to the unaudited financial statements of the applicable entity for the one month ended January 31, 2003 and for the four months ended April 30, 2003, respectively, and found them to be in agreement.
3. Made inquiries of certain officials of the Trust who have responsibility for financial and accounting matters about:
 - (a) the basis for determination of the pro-forma adjustments; and
 - (b) whether the pro-forma financial statements comply as to form in all material respects with *Securities Acts* of the various Provinces of Canada (the "Acts").

The officials:

- (a) described to us the basis for determination of the pro-forma adjustments, and
 - (b) stated that the pro-forma statements comply as to form in all material respects with the Acts.
4. Read the notes to the pro-forma statements, and found them to be consistent with the basis described to us for determination of the pro-forma adjustments.
5. Recalculated the application of the pro-forma adjustments to the aggregate of the amounts in the columns captioned "APF Energy Trust, Hawk Oil Inc., Nycan Energy Corp. and Great Northern Exploration Ltd." for the year ended December 31, 2003 and found the amounts in the columns captioned "Total" to be arithmetically correct.

A pro-forma financial statement is based on management assumptions and adjustments which are inherently subjective. The foregoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with respect to management's assumptions, the pro-forma adjustments, and the application of the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro-forma financial statements, and we therefore make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

(Signed) "PricewaterhouseCoopers LLP"
Chartered Accountants

Calgary, Alberta
June 28, 2004

APF Energy Trust

Pro-Forma Consolidated Statement of Operations

(Unaudited)

December 31, 2003

	APF Energy Trust Year Ended December 31, 2003	Hawk Oil Inc. One Month Ended January 31, 2003	Nycan Energy Corp. Four Months Ended April 30, 2003	Great Northern Exploration Ltd. Year Ended December 31, 2003	Adjustments (Note 2)	Total
(\$000s except per unit amounts)						
Revenue						
Oil and natural gas	163,532	3,066	6,423	51,317		224,338
Royalties expense, net of ARTC	(32,473)	(419)	(1,257)	(9,928)	(500) (vi)	(44,577)
Other operating revenue	1,925	-	62	-		1,987
	132,984	2,647	5,229	41,389	(500)	181,748
Expenses						
Operating	32,370	670	979	9,617		43,636
General and administrative - net	10,023	1,864	2,976	1,363	(2,160) (vii)	14,066
Stock based compensation expense	1,241					1,241
Interest on long-term debt	4,171	25	100	1,172	(381) (ii)	5,087
Capital and other taxes	2,720				534 (v)	3,254
Depletion and amortization	50,417	443	1,155	12,021	11,950 (i)(iv)	75,986
Site restoration	3,327				542 (iv)	3,869
	104,269	3,003	5,210	24,173	10,485	147,139
Operating income	28,715	(356)	19	17,216	(10,985)	34,609
Provision for income taxes (recovery)						
Current	-	5	18	306	204 (iii)	-
Future	(14,333)	(50)	25	6,405	(534) (v) (4,209) (iii)	(12,163)
Net income for the period	43,048	(311)	(24)	10,505	(6,446)	46,772
Net income per unit - basic	1.32					0.87
Net income per unit - diluted	1.21					0.87

1. Basis of Presentation

The pro-forma consolidated financial statements of APF Energy Trust (the "Trust"), which owns a 99% interest in certain oil and gas royalties, have been prepared by management to give effect to the purchase of Hawk Oil Inc. ("Hawk"), Nycan Energy Corp. ("Nycan") and Great Northern Exploration Ltd. ("GNEL"). Hawk, Nycan and GNEL were involved in oil and gas exploration, development and production in western Canada. The pro-forma consolidated financial statements have been prepared from information derived from the December 31, 2003 audited consolidated historical financial statements of the Trust, the one month January 31, 2003 unaudited financial statements of Hawk, the four months ended April 30, 2003 unaudited financial statements of Nycan, the December 31, 2003 audited financial statements of GNEL, and the assumptions set out in note 2 below.

The Hawk shares were purchased by the Trust through a take-over bid, which closed February 5, 2003. The Nycan shares were purchased by the Trust through a take-over bid, which closed April 28, 2003. The GNEL Shares were purchased by the Trust through a take-over bid, which closed June 4, 2004. The pro-forma consolidated statement of operations gives effect to those transactions as if they occurred January 1, 2003. The pro-forma consolidated balance sheet gives effect to those transactions at December 31, 2003.

The pro-forma consolidated financial statements do not give effect to any transaction that does not meet the significant test rules as defined by various securities regulators.

The pro-forma consolidated financial statements may not be indicative of the financial position or the results of operations of the Trust which will be obtained upon completion of the acquisition of GNEL (the "Acquisition"). In preparing the pro-forma consolidated financial statements, no adjustments have been made to reflect any operating or administrative cost savings that may result from the operations of the consolidated assets.

Accounting policies used in the preparation of the pro-forma financial statements are in accordance with those disclosed in the Trust's audited financial statements as at and for the year ended December 31, 2003. The acquisition of Hawk, Nycan and GNEL have been accounted for as business acquisitions. In the opinion of management, the pro-forma financial statements include all adjustments necessary for fair presentation.

The pro-forma statements should be read in conjunction with the Trust's consolidated financial statements as at and for the year ended December 31, 2003, the unaudited financial statements of Hawk for the one month ended January 31, 2003, the unaudited financial statements of Nycan for the three months ended March 31, 2003 and the audited financial statements of GNEL for the year ended December 31, 2003.

The Trust is an open-ended investment trust under the laws of the Province of Alberta.

The royalty interests (the "Royalty") in producing oil and natural gas properties acquired from APF Energy Inc. and APF Energy Limited Partnership (collectively "APF") effectively transfer 99% of the economic interest in such properties to the Unitholders. The Royalty constitutes a royalty interest in the oil and natural gas properties owned by APF but does not confer ownership in the underlying resource properties. APF is permitted to borrow funds to finance the purchase of additional properties and tangibles, for capital expenditures or for other financial obligations or encumbrances in respect of the properties should the properties not generate sufficient income to repay debt. The Trust is entitled to 99% of the production and incidental revenues from the properties less all costs and expenses in respect of the properties, taxes in respect of the properties, general and administrative costs of APF and the Royalty and debt service charges (including principal repayments). The Trust is required to reimburse APF for Crown royalties and charges in respect of production allocable to the Royalty.

2. Pro-forma adjustments and assumptions

The pro-forma consolidated statement of operations has been prepared as if the proposed transactions took place on January 1, 2003.

- (i) The purchase price allocated to the Hawk capital assets, the Nycan capital assets and the GNEL assets are amortized on a unit of production basis;
- (ii) the interest for the change of bank debt related to the purchases after the use of cash from the issue of Trust Units, and from the issue of Debentures pursuant to prospectuses, has been recorded at 5% per annum with no deemed principal repayments (see note 3);

- (iii) current taxes were adjusted to account for income taxes as if the income from the acquisitions subject to the royalty calculation was in effect January 1, 2003. The taxes on the incremental income are assumed to be passed to the Unitholders through the royalty calculation. The future income tax expense has been adjusted to reflect the impact on earnings of the transactions at the maximum statutory rate;
- (iv) site restoration in the case of Hawk, Nycan, and GNEL has been reclassified from depletion and amortization;
- (v) a Saskatchewan surtax is applied to certain properties and capital taxes have been reclassified out of income taxes;
- (vi) Alberta Royalty Tax Credit was adjusted to reduce the amount to the maximum allowable for the year;
- (vii) compensation costs in Nycan arising from the sale of the company have been eliminated;
- (viii) the net income on a per unit basis is based on 48,447,738 Trust Units assumed outstanding for the period (52,875,738 diluted).

3. Unitholders' equity

The authorized unit capital of the Trust consists of 500,000,000 Trust Units of which 22,942,417 Trust Units were outstanding at December 31, 2002, with additional 3,990,461 Trust Units issued as part of the settlement for the Hawk shares, 1,342,004 Trust Units issued as part of the settlement for the CanScot Shares, 5,300,000 Trust Units issued under the March 19, 2003 prospectus, 4,765,000 Trust Units issued under the January 27, 2004 prospectus and the assumption that 13,593,621 Trust Units will be issued to the shareholders of GNEL. Pursuant to the June 26, 2003 prospectus, the Trust sold 50,000, 9.40% Convertible Unsecured Subordinated Debentures at a price of \$1,000 per Debenture. The maturity date is July 31, 2008. The Debentures are convertible at the holder's option into fully paid Trust Units at a conversion price of \$11.25 per Trust Unit, being a conversion rate of 88.8889 Trust Units for each \$1,000 principal amount of Debentures. The Trust is also authorized to issue an unlimited number of Special Voting Units.

4. GNEL Acquisition

On April 6, 2004, APF Energy and GNEL entered into an agreement whereby APF Energy agreed to acquire GNEL at a price of \$5.05 per share, payable at the option of the GNEL shareholders in cash for a maximum of 25% of the Purchase Price, or in Trust Units of the Trust, based on an exchange ratio of 0.414614 Trust Units for each GNEL Share. On June 4, 2004 APF Energy took up all of the GNEL Shares tendered to the offer to acquire all of the shares of GNEL.

The pro-forma consolidated statement of operations has been prepared based on the fact that the GNEL shareholders elected for the maximum cash.

SCHEDULE B

MANAGEMENT'S
REPORT TO THE
SHAREHOLDERS

The accompanying consolidated financial statements of Great Northern Exploration Ltd. are the responsibility of management. The financial and operating information presented in this Annual Report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies disclosed in the notes to the financial statements and in accordance with generally accepted accounting principles in Canada. When necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.



James M. Saunders, P. Eng.
President & Chief Executive Officer



John M. Sapich, C.A.
Vice President, Finance & Chief Financial Officer

March 18, 2004

CONSOLIDATED FINANCIAL STATEMENTS

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Great Northern Exploration Ltd. as at December 31, 2003 and 2002 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada

March 17, 2004

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEET

<i>As at December 31,</i>		2003	2002
		\$	\$
ASSETS			
<i>Current assets</i>			
Accounts receivable		12,456,000	5,192,000
Prepaid expenses		609,000	382,000
		13,065,000	5,574,000
Property and equipment	(note 5)	120,491,000	34,789,000
		133,556,000	40,363,000
LIABILITIES AND SHAREHOLDERS' EQUITY			
<i>Current liabilities</i>			
Accounts payable		19,754,000	10,656,000
Bank debt	(note 6)	38,555,000	5,107,000
		58,309,000	15,763,000
Future income taxes	(note 11)	8,097,000	—
Future site restoration	(note 7)	630,000	136,000
		67,036,000	15,899,000
<i>Shareholders' equity</i>			
Share capital	(note 8)	54,281,000	22,866,000
Contributed surplus	(note 3)	136,000	—
Retained earnings		12,103,000	1,598,000
		66,520,000	24,464,000
Subsequent events	(note 14)	133,556,000	40,363,000

On behalf of the Board of Directors:



James M. Saunders

Director



Warren Steckley

Director

(See accompanying notes to the consolidated financial statements)

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENT OF OPERATIONS AND RETAINED EARNINGS

<i>Year ended December 31.</i>	2003	2002
	\$	\$
<i>Revenue</i>		
Petroleum and natural gas sales	51,317,000	12,170,000
Royalties, net	(9,928,000)	(1,965,000)
	41,389,000	10,205,000
<i>Expenses</i>		
Operating	9,617,000	2,626,000
General and administrative	1,363,000	938,000
Financial charges	1,172,000	220,000
Depletion and depreciation	12,021,000	2,848,000
	24,173,000	6,632,000
<i>Earnings before taxes</i>	17,216,000	3,573,000
Capital taxes	306,000	116,000
Future income taxes (note 11)	6,405,000	1,663,000
	6,711,000	1,779,000
<i>Net earnings</i>	10,505,000	1,794,000
<i>Retained earnings (deficit), beginning of year</i>	1,598,000	(196,000)
<i>Retained earnings, end of year</i>	12,103,000	1,598,000
<i>Net earnings per share</i>		
Basic	0.30	0.08
Diluted	0.29	0.07

(See accompanying notes to the consolidated financial statements)

CONSOLIDATED
STATEMENT OF
CASH FLOW

<i>Year ended December 31,</i>	2003	2002
	\$	\$
<i>Cash flow related to the following activities</i>		
<i>Operating</i>		
Net earnings for the period	10,505,000	1,794,000
Items not affecting cash:		
Depletion and depreciation	12,021,000	2,848,000
Stock-based compensation <i>(note 3)</i>	136,000	—
Future income taxes	6,405,000	1,663,000
Cash flow from operations	29,067,000	6,305,000
Changes in non-cash operating working capital items	3,717,000	(706,000)
	32,784,000	5,599,000
<i>Financing</i>		
Change in bank debt	33,448,000	(8,888,000)
Share issuance, net	33,106,000	4,276,000
	66,554,000	(4,612,000)
<i>Cash available for investment activities</i>	99,338,000	987,000
<i>Investing</i>		
Property and equipment additions	(96,880,000)	(13,602,000)
Site restoration expenditures	(348,000)	—
Changes in non-cash investing working capital items	(2,110,000)	4,401,000
	(99,338,000)	(9,201,000)
<i>Change in cash</i>	—	(8,214,000)
<i>Cash, beginning of year</i>	—	8,214,000
<i>Cash, end of year</i>	—	—

(See accompanying notes to the consolidated financial statements)

YEAR ENDED DECEMBER 31, 2003

(all dollar amounts in thousands of dollars, unless otherwise stated)

1. NATURE OF OPERATIONS

The shareholders of Great Northern Exploration Ltd. ("the Company"), approved a name change from Ascot Energy Resources Ltd. ("Ascot") and a share consolidation on the basis of one new share for every five existing common shares at the Annual and Special Meeting held on September 26, 2002. All share data including number of common shares outstanding, per share data and stock options outstanding have been adjusted to reflect the share consolidation.

On July 10, 2002, the Company acquired all the shares of Great Northern Exploration Ltd. ("Great Northern"), a private corporation. Great Northern was incorporated on August 9, 2001 and commenced active operations in September 2001.

The transaction has been accounted for as a reverse takeover of the Company by Great Northern. Accordingly, the results of operations for 2002 include those of Great Northern from the date of incorporation and those of the Company from the date of the acquisition to December 31, 2002.

The Company is engaged primarily in the exploration for and development and production of petroleum and natural gas in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

a) Basis of Presentation

The consolidated financial statements include the accounts of Great Northern Exploration Ltd. (the "Company") and its wholly-owned subsidiaries.

The Company's financial statements have been prepared in accordance with Canadian generally accepted accounting principles and reflect the following policies:

b) Petroleum and Natural Gas Operations

i) CAPITALIZED COSTS

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing oil and gas properties and related reserves are capitalized into a single Canadian cost center. Costs include land acquisition costs, geological and geophysical expenditures, costs of drilling both productive and non-productive wells, well equipment and certain other overhead expenditures related to exploration.

Gains or losses on the sale or disposition of oil and gas properties are not ordinarily recognized except under circumstances which result in a significant revision of depletion rates.

ii) DEPLETION AND DEPRECIATION

Petroleum and natural gas properties and related equipment, excluding undeveloped properties, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves. For purposes of this calculation, petroleum and natural gas reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes salvage values and the cost of unproved properties. Costs of acquiring and evaluating unproved properties are excluded from the depletion base until it is determined whether proved reserves are attributable to the properties or impairment occurs.

III) CEILING TEST

In applying the full-cost method, the Company calculates a "ceiling test" to capitalized costs to ensure that such costs do not exceed future net revenues from estimated production of proven reserves, using prices and costs in effect at the Company's year end, less administrative, financing, site restoration and abandonment, and income tax expenses, plus the costs of unproven properties. Any reduction in value as a result of the ceiling test is charged to operations as an element of depletion and depreciation expense. Undeveloped land is evaluated for impairment at each balance sheet date.

c) *Joint Ventures*

Substantially all of the Company's exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

d) *Flow-through Shares*

The Company from time to time issues flow-through shares. Under these financing agreements, shares are issued at a fixed price with the resultant proceeds used to fund exploration and development work within a defined time period. The exploration and development expenditures funded by flow-through arrangements are renounced to investors in accordance with the appropriate tax legislation. A future tax liability is recorded and share capital is reduced by the estimated tax benefits transferred to shareholders.

e) *Future Site Restoration and Abandonment Costs*

Estimated future costs relating to site restoration and abandonment of petroleum and natural gas properties and related facilities are accrued on a unit of production basis over the estimated life of the proved reserves. Costs are based on engineering estimates, net of expected recoveries, based upon current prices and in accordance with current legislation, technology and industry standards.

f) *Future Income Taxes*

Income taxes are calculated using the liability method of tax allocation. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. The effect on future income tax liabilities or assets of a change in tax rates is recognized in net income in the period in which the change occurs.

g) *Stock-Based Compensation Plan*

The Company has a stock-based compensation plan which is described in note 9. As of January 1, 2003, the Company adopted a new accounting standard on stock-based compensation. Stock option expense is recorded as general and administrative expense for all options granted on or after January 1, 2003, with a corresponding increase recorded to contributed surplus. The expense related to options issued during 2002 is disclosed as proforma information in note 9.

The fair value of options granted are estimated at the date of the grant using the Black-Scholes valuation model. Upon the exercise of the stock options, consideration paid by employees or directors together with the amount previously recognized in contributed surplus, is credited to share capital.

h) *Per Share Amounts*

Per share amounts are calculated on the basis of the weighted average number of common shares outstanding during the period.

The treasury stock method of calculating diluted per share amounts is used whereby any proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

i) Revenue Recognition

Petroleum and natural gas sales are recognized as revenue at the time the respective commodities are delivered to purchasers.

j) Financial Instruments

Settlement of crude oil and natural gas swap agreements, which have been arranged as a hedge against commodity price, are reflected in revenues at the time of sale of the related hedged production.

k) Measurement Uncertainty

The amount recorded for depletion and depreciation of property and equipment, the provision for site restoration costs and the ceiling test calculation are based upon estimates of gross proved reserves, production rates, crude oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

**3. CHANGE IN
ACCOUNTING
POLICY**

Stock-Based Compensation Plan

In September 2003, the Canadian Institute of Chartered Accountants ("CICA") amended Handbook Section 3870 - "Stock-based Compensation and Other Stock-based Payments". Pursuant to new transitional rules approved by the CICA, the Company early adopted the amended standard on a prospective basis and now records stock-based compensation expense in the Consolidated Statement of Operations for all common share options granted to employees and directors on or after January 1, 2003. As a result of adopting this amended standard, net earnings for the year ended December 31, 2003 decreased by \$136 thousand and contributed surplus increased by an equal amount.

Common share options granted prior to January 1, 2003 do not result in a compensation expense and the Company continues to disclose the proforma earnings impact of related stock-based compensation expense for these options (note 9).

**4. BUSINESS
COMBINATION**

On July 10, 2002, the business transaction between Ascot and Great Northern was formally approved. This reverse takeover by Great Northern of Ascot resulted in Ascot issuing 6.5 common shares for each 1 share of Great Northern in which there were 14,052,000 Great Northern common shares issued and outstanding. Total shares issued pursuant to the business transaction were 91,338,000 or 18,267,600 common shares after the above mentioned share consolidation.

The Company acquired all of the shares of Great Northern and has accounted for the transaction as an acquisition of the Company by Great Northern.

Net assets acquired	\$
Property and equipment	20,573
Working capital	626
Future income tax asset	3,215
Long-term debt	(13,995)
Transaction costs	(2,167)
Purchase price - common share equity value	<u>8,252</u>

5. PROPERTY,
PLANT AND
EQUIPMENT

		Accumulated Depletion and Depreciation	Net Book Value
2003	Cost		
	\$	\$	\$
Petroleum and natural gas properties	134,644	14,219	120,425
Office equipment	88	22	66
	<u>134,732</u>	<u>14,241</u>	<u>120,491</u>
2002	Cost	Accumulated Depletion and Depreciation	Net Book Value
	\$	\$	\$
Petroleum and natural gas properties	37,457	2,702	34,755
Office equipment	47	13	34
	<u>37,504</u>	<u>2,715</u>	<u>34,789</u>

The Company has capitalized, as part of petroleum and natural gas properties, indirect exploration overhead relating to property acquisition, exploration and development activities of \$553 thousand for the year ended December 31, 2003 (2002 - \$147 thousand).

Undeveloped land costs of \$9.4 million (2002 - \$6.0 million) have been excluded from the amount subject to depletion and depreciation.

6. CREDIT FACILITIES

	2003	2002
	\$	\$
Prime rate advances	8,555	107
Bankers' acceptances	30,000	5,000
	<u>38,555</u>	<u>5,107</u>

Subsequent to December 31, 2003, the Company amended its demand revolving credit facility to a maximum of \$70 million. The credit facility bears interest at the lenders' prime rate or at the Bankers' Acceptance rate plus a stamping fee of 1.25%. The \$70 million borrowing base is subject to a semi-annual and annual review by the lender. The credit facility is secured by a first fixed and floating charge debenture in the amount of \$100 million covering all the Company's assets.

7. SITE
RESTORATION
AND
ABANDONMENTS

At December 31, 2003, total future removal and site restoration costs to be accrued over the life of the remaining proved reserves were estimated, net of recoveries, at \$7.7 million (2002 - \$2.1 million) of which \$630 thousand (2002 - \$136 thousand) has been accrued. This estimate is subject to change based on amendments to environmental laws and as new information concerning operations becomes available.

8. SHARE CAPITAL *a) Authorized*

Unlimited number of common voting shares

Unlimited number of preferred shares, issuable in series

b) Issued

	Number of Shares	Amount \$
Balance, December 31, 2001	17,065,100	11,890
Issued for cash	1,202,500	550
Acquisition of Ascot Energy Resources Ltd.	10,726,182	8,252
Exercise of stock options	110,500	85
Flow-through shares issued	1,379,400	4,000
Tax benefit renounced to shareholders	—	(1,705)
Share issue costs, net of tax effect	—	(206)
Balance, December 31, 2002	30,483,682	22,866
Issued on private placement	4,000,000	13,800
Issued on private placement	3,750,000	15,000
Exercise of stock options	125,000	142
Flow-through shares issued	1,100,000	6,050
Tax benefit renounced to shareholders	—	(2,456)
Share issue costs, net of future tax	—	(1,121)
Balance, December 31, 2003	39,458,682	54,281

In December 2003, 1,100,000 flow-through common shares were issued at a price of \$5.50 per share for gross proceeds of \$6.1 million. Under the terms of the flow-through agreement, the Company is required to expend \$6.1 million on qualifying crude oil and natural gas expenditures prior to December 31, 2004. As at December 31, 2003, the Company had incurred qualifying expenditures in the amount of \$0.6 million.

**9. STOCK-BASED
COMPENSATION**

The Company has implemented a Stock Option Plan for directors and employees. Options under the Plan vest over a four year period with 25% vesting upon each anniversary date of the grant. As of December 31, 2003, there were 3,001,250 common shares reserved for issuance to eligible participants. At December 31, 2003, 3,405,875 (2002 - 2,474,875) options with exercise prices between \$0.77 and \$4.55 were outstanding and exercisable at various dates to December 11, 2008. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

The following tables summarize the information about the share options as at December 31:

	2003		2002	
	Weighted average exercise		Weighted average exercise	
<i>Fixed Options</i>	Shares	price	Shares	price
Outstanding at beginning of year	2,474,875	\$1.36	1,397,500	\$0.77
Granted	1,268,875	\$3.80	1,200,875	\$1.99
Exercised	(125,000)	\$1.15	(110,500)	\$0.77
Cancelled	(212,875)	\$2.23	(13,000)	\$0.77
Outstanding at end of year	3,405,875	\$2.22	2,474,875	\$1.36
Options exercisable at year end	637,000	\$1.01	232,375	\$0.77

	Options outstanding			Options exercisable	
	Number outstanding at December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable at December 31, 2003	Weighted average exercise price
<i>Range of exercise prices</i>					
\$ 0.77 - \$ 1.50	1,192,750	7.9	\$ 0.77	497,250	\$ 0.77
\$ 1.85 - \$ 2.20	975,225	8.5	\$ 2.01	139,750	\$ 1.87
\$ 2.63 - \$ 3.95	564,275	9.1	\$ 3.27	—	\$ —
\$ 4.00 - \$ 4.55	673,625	8.8	\$ 4.22	—	\$ —
	3,405,875		\$ 2.22	637,000	\$ 1.01

For options granted to employees from January 1, 2002 to December 31, 2002, the Company follows the settlement method of accounting. Since all options were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the 2002 option grants. Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards, the Company's net earnings and net earnings per share for the year ended December 31, 2002 would have been the pro forma amounts indicated following:

	2003	2002
	\$	\$
Net earnings		
As reported	10,505	1,794
Pro forma	10,345	1,750
Net earnings per common share - basic		
As reported	0.30	0.08
Pro forma	0.30	0.08
Net earnings per common share - diluted		
As reported	0.29	0.07
Pro forma	0.28	0.07

For options granted after January 1, 2003, the Company follows the fair value method (note 3).

The weighted average fair market value of options granted in the year ended December 31, 2003 are \$1.39 per option. The fair market of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions:

	2003	2002
Risk-free interest rate	4.50%	4.00%
Estimated hold period prior to exercise (years)	5	4
Volatility in the price of the Company's common shares	38%	44%
Dividend per share	\$0.00	\$0.00

10. PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year.

In the calculation of diluted per share amounts, options under the stock option plan are assumed to have been converted or exercised on the later of the beginning of the year and the date granted. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market rate.

	2003	2002
Weighted average shares outstanding (thousands)		
Basic	34,865	23,024
Diluted	36,318	24,016

11. INCOME TAXES

The provision for income tax differs from the result which would be obtained by applying the combined Federal and Provincial statutory income tax rates to income before taxes. This difference results from the following:

	2003	2002
	\$	\$
Earnings (loss) before taxes	17,216	3,573
Statutory income tax rate	40.6%	42.8%
Expected income tax	6,990	1,529
Increase (decrease) resulting from:		
Non-deductible crown charges	2,769	760
Resource allowance	(3,044)	(597)
Statutory rate adjustment	(310)	(224)
Other	—	23
Change in valuation allowance	—	172
Provision for taxes	6,405	1,663

The future income tax liability is comprised of temporary differences related to the following:

	2003	2002
	\$	\$
Property and equipment	(9,572)	(928)
Statutory tax rate adjustment	339	286
Future site restoration	201	44
Share issue	759	313
Non-capital losses	946	827
Valuation allowance	(770)	(542)
Future income taxes	8,097	—

**12. SUPPLEMENTAL
CASH FLOW
INFORMATION**

Changes in non-cash working capital:

	2003	2002
	\$	\$
Accounts receivable	(7,264)	(3,187)
Prepaid expenses	(227)	509
Accounts payable	9,098	6,373
Changes in non-cash working capital	1,607	3,695
These changes relate to the following activities:		
Operating activities	3,717	(706)
Investing activities	(2,110)	4,401
	1,607	3,695

Amounts paid during the year relating to interest expense and capital taxes are as follows:

	2003	2002
	\$	\$
Interest paid in the year	1,204	220
Capital taxes paid in the year	210	—
	1,414	220

13. FINANCIAL INSTRUMENTS

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

a) Commodity Price Risk Management

Financial instruments are entered into by the Company to protect the downside prices received on the sale of a portion of its crude oil and natural gas production. The agreements entered into are forward transactions providing the Company with a range of fixed prices on the commodities sold. Petroleum and natural gas revenue for the year ended December 31, 2003 include losses of \$1.7 million (2002 - \$133 thousand loss) on those transactions.

The following contracts were outstanding as at December 31, 2003:

Commodity	Type	Term	Volume	Price	Index
Natural gas	Fixed	January 2004 - March 2004	6,000 GJ's/d	\$6.57/GJ	AECO
Crude oil	Fixed	January 2004 - March 2004	600 bbls/d	US \$28.70/bbl	WTI
Crude oil	Fixed	April 2004 - June 2004	600 bbls/d	US \$27.50/bbl	WTI
Crude oil	Fixed	July 2004 - September 2004	400 bbls/d	US \$28.25/bbl	WTI
Crude oil	Fixed	October 2004 - December 2004	300 bbls/d	US \$27.30/bbl	WTI

The estimated fair value at December 31, 2003 of these transactions, had the contracts been settled at that time, would be a loss of \$487 thousand.

b) Credit Risk Management

The Company has estimated that the fair value of its financial instruments, which include accounts receivable, accounts payable and accrued liabilities, and long-term debt, approximate their carrying values.

The majority of the Company's accounts receivable are with other companies in the oil and gas industry and are subject to normal industry credit risk.

14. SUBSEQUENT EVENTS

On January 22, 2004, the Company acquired crude oil and natural gas assets that produce approximately 580 barrels of oil equivalent per day of production for approximately \$23 million. The acquisition included working interests in existing Company operated producing properties, gas processing facilities, infrastructure and undeveloped land.

As a result of completion of the above mentioned acquisition, the Company renegotiated its credit facilities as described in note 6.

On February 2, 2004, the Company issued 4,250,000 common shares at a price of \$4.50 per share for gross proceeds of \$19.1 million.

SCHEDULE C

GREAT NORTHERN EXPLORATION LTD.

CONSOLIDATED BALANCE SHEET

	March 31, 2004	December 31, 2003
	<i>(unaudited)</i>	<i>(Restated – note 3)</i>
	\$	\$
ASSETS		
Current assets		
Accounts receivable	11,473,000	12,456,000
Prepaid expenses	546,000	609,000
	12,019,000	13,065,000
Property and equipment (note 4)	160,448,000	125,718,000
	172,467,000	138,783,000
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	21,916,000	19,754,000
Bank debt (note 5)	45,596,000	38,555,000
	67,512,000	58,309,000
Future income taxes	9,641,000	8,097,000
Asset retirement obligations (note 8)	7,866,000	6,923,000
	85,019,000	73,329,000
Shareholders' equity		
Share capital (note 6)	72,859,000	54,281,000
Contributed surplus	251,000	136,000
Retained earnings	14,338,000	11,037,000
	87,448,000	65,454,000
Subsequent event (note 10)	172,467,000	138,783,000

(See accompanying notes to the consolidated financial statements)

GREAT NORTHERN EXPLORATION LTD.

CONSOLIDATED STATEMENT OF OPERATIONS AND RETAINED EARNINGS

<i>Three months ended March 31,</i>	2004	2003 (Restated – note 3) <i>(unaudited)</i>
	\$	\$
Revenue		
Petroleum and natural gas sales	19,529,000	8,895,000
Royalties, net	(3,909,000)	(2,019,000)
	15,620,000	6,876,000
Expenses		
Operating	3,892,000	1,367,000
General and administrative	304,000	324,000
Financial charges	538,000	51,000
Depletion, depreciation and accretion (note 8)	5,591,000	1,531,000
	10,325,000	3,273,000
Earnings before taxes	5,295,000	3,603,000
Capital taxes	94,000	29,000
Future income taxes	1,900,000	1,402,000
	1,994,000	1,431,000
Net earnings	3,301,000	2,172,000
Retained earnings, beginning of period	12,103,000	1,598,000
Retroactive application of change in accounting policy (note 3(b))	(1,066,000)	(390,000)
Retained earnings, end of period	14,338,000	3,380,000
Net earnings per share		
Basic	\$0.08	\$0.07
Diluted	\$0.08	\$0.07

(See accompanying notes to the consolidated financial statements)

GREAT NORTHERN EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CASH FLOW

<i>Three months ended March 31,</i>	2004	2003 (Restated – note 3)
	(unaudited)	
	\$	\$
Cash flow related to the following activities		
Operating		
Net earnings for the period	3,301,000	2,337,000
Items not affecting cash:		
Depletion, depreciation and accretion	5,591,000	1,366,000
Future income taxes	1,900,000	1,402,000
Stock-based compensation	115,000	-
Cash flow from operations	10,907,000	5,105,000
Changes in non-cash operating working capital items	520,000	1,584,000
	11,427,000	6,689,000
Financing		
Change in bank debt	7,041,000	3,971,000
Share issuance, net	18,222,000	32,000
	25,263,000	4,003,000
Cash available for investment activities	36,690,000	10,692,000
Investing		
Property and equipment additions	(39,290,000)	(8,974,000)
Site restoration expenditures	(88,000)	(41,000)
Changes in non-cash investing working capital items	2,688,000	(1,677,000)
	(36,690,000)	(10,692,000)
Change in cash	-	-
Cash, beginning of period	-	-
Cash, end of period	-	-

(See accompanying notes to the consolidated financial statements)

GREAT NORTHERN EXPLORATION LTD.

SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

THREE MONTHS ENDED MARCH 31, 2004

(unaudited)

(tabular amounts in thousands of dollars, unless otherwise stated)

1. NATURE OF OPERATIONS

The Company is engaged primarily in the exploration for and development and production of petroleum and natural gas in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

a) Basis of Presentation

The consolidated financial statements include the accounts of Great Northern Exploration Ltd. (the "Company") and its wholly-owned subsidiaries.

The interim consolidated financial statements and the notes thereto of the Company have been prepared following the same accounting policies and methods of computation as the audited consolidated financial statements of the Company as at December 31, 2003 except as disclosed in note 3. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2003.

3. CHANGE IN ACCOUNTING POLICY

a) Full Cost Accounting Guideline

In January 2004, the Company adopted Accounting Guideline 16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants ("CICA") which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil & Gas Industry".

The recoverability of a cost center is tested by comparing the carrying value of the cost center to the sum of the undiscounted cash flows expected from the cost center's use and eventual disposition. If the carrying value is unrecoverable the cost center is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a credit adjusted risk free rate.

Under Accounting Guideline 5, future net revenues for ceiling test purposes were based on proved reserves and were not discounted. Estimated future general and administrative costs and financing charges associated with future net revenues were deducted in arriving at the "ceiling".

There were no charges to net income, property, plant and equipment or any other reported amounts in the consolidated financial statements as a result of adopting this guideline.

b) Asset Retirement Obligation

In January 2004, the Company adopted CICA Handbook Section 3110, "Asset Retirement Obligations". This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

The Company recognizes the fair value of its asset retirement obligation ("ARO") in the period in which it is incurred and when a reasonable estimate of fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs.

Previously, the Company recognized a provision for site restoration and abandonment costs calculated on the unit-of-production method over the life of the petroleum and natural gas properties based on total estimated proved reserves and the estimated future liability.

This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes as follows:

Consolidated Balance Sheet as at December 31, 2003

	<u>As Reported</u>	<u>Change</u>	<u>As Restated</u>
	\$	\$	\$
Assets			
Property and equipment	120,491	5,227	125,718
Liabilities and shareholders' equity			
Future site restoration	630	(630)	-
Asset retirement obligations	-	6,923	6,923
Retained earnings	12,103	(1,066)	11,037

Consolidated Statement of Operations and Retained Earnings for the Three Months ended March 31, 2003

	<u>As Reported</u>	<u>Change</u>	<u>As Restated</u>
	\$	\$	\$
Depletion and depreciation	1,366	90	1,456
Accretion	-	75	75
Net earnings	2,337	(165)	2,172

There was no impact on the Company's cash flow as a result of adopting this new policy. See note 7 for additional information on the asset retirement obligation and the impact on the consolidated financial statements.

4. PROPERTY AND EQUIPMENT

	March 31, 2004		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	\$	\$	\$
Petroleum and natural gas properties	180,938	20,549	160,389
Office equipment	92	33	59
	<u>181,030</u>	<u>20,582</u>	<u>160,448</u>

	December 31, 2003		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	\$	\$	\$
Petroleum and natural gas properties	140,773	15,121	125,652
Office equipment	88	22	66
	<u>140,861</u>	<u>15,143</u>	<u>125,718</u>

The Company has capitalized, as part of petroleum and natural gas properties, indirect exploration overhead relating to property acquisition, exploration and development activities of \$115 thousand for the three months ended March 31, 2004 (year ended December 31, 2003 - \$553 thousand).

At March 31, 2004, undeveloped land costs of \$9.4 million (December 31, 2003 - \$9.4 million) have been excluded from the amount subject to depletion and depreciation.

5. CREDIT FACILITIES

	March 31, 2004	December 31, 2003
	\$	\$
Prime rate advances	5,596	8,555
Bankers' acceptances	40,000	30,000
	<u>45,596</u>	<u>38,555</u>

The Company has a demand revolving credit facility to a maximum of \$70 million. The credit facility bears interest at the lenders' prime rate or at the Bankers' Acceptance rate plus a stamping fee of 1.25%. The \$70 million borrowing base is subject to a semi-annual and annual review by the lender. The credit facility is secured by a first fixed and floating charge debenture in the amount of \$100 million covering all the Company's assets.

6. SHARE CAPITAL

a) Authorized

Unlimited number of common voting shares

Unlimited number of preferred shares, issuable in series

b) Issued

	Number of Shares	Amount \$
Balance, December 31, 2002	30,483,682	22,866
Issued on private placement	4,000,000	13,800
Issued on private placement	3,750,000	15,000
Exercise of stock options	125,000	142
Flow-through shares issued	1,100,000	6,050
Tax benefit renounced to shareholders	-	(2,456)
Share issue costs, net of future tax	-	(1,121)
Balance, December 31, 2003	39,458,682	54,281
Issued on private placement	4,250,000	19,125
Exercise of stock options	6,250	12
Share issue costs, net of future tax	-	(559)
Balance, March 31, 2004	43,714,932	72,859

In December 2003, 1,100,000 flow-through common shares were issued at a price of \$5.50 per share for gross proceeds of \$6.1 million. Under the terms of the flow-through agreement, the Company is required to expend \$6.1 million on qualifying crude oil and natural gas expenditures prior to December 31, 2004.

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year.

The reconciling items between the basic and diluted average common shares outstanding are outstanding stock options.

	Three months ended March 31,	
	2004	2003
Weighted average shares outstanding (thousands)		
Basic	42,173	30,499
Diluted	43,876	31,637

7. STOCK-BASED COMPENSATION

The Company has implemented a Stock Option Plan for directors and employees. Options under the Plan vest over a four year period with 25% vesting upon each anniversary date of the grant. As of March 31, 2004, there were 2,995,000 common shares reserved for issuance to eligible participants. At March 31, 2004, 3,423,375 (December 31, 2003 - 3,405,875) options with exercise prices between \$0.77 and \$4.60 were outstanding and exercisable at various dates to December 11, 2008. On April 6, 2004, 435,375 conditionally granted share options with an exercise price of \$4.25 were cancelled. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

The following tables summarize the information about the share options:

	Three months ended March 31, 2004		Year ended December 31, 2003	
	Shares	Weighted average exercise price	Shares	Weighted average exercise price
Fixed Options				
Outstanding at beginning of period	3,405,875	\$2.22	2,474,875	\$1.36
Granted	93,750	\$4.33	1,268,875	\$3.80
Exercised	(6,250)	\$2.00	(125,000)	\$1.15
Cancelled	(70,000)	\$4.00	(212,875)	\$2.23
Outstanding at end of period	3,423,375	\$2.24	3,405,875	\$2.22
Options exercisable at period end	682,750	\$1.12	637,000	\$1.01

Range of exercise prices	Options outstanding			Options exercisable	
	Number outstanding at March 31, 2004	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable at March 31, 2004	Weighted average exercise price
\$0.77 - \$1.50	1,192,750	7.7	\$0.77	500,500	\$0.77
\$1.85 - \$2.20	968,975	8.3	\$2.01	133,500	\$1.86
\$2.63 - \$3.95	564,275	8.7	\$3.27	48,750	\$2.66
\$4.00 - \$4.60	697,375	8.6	\$4.26	-	\$ -
	3,423,375		\$2.24	682,750	\$1.12

For options granted to employees from January 1, 2002 to December 31, 2002, the Company follows the settlement method of accounting. Since all options were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the 2002 option grants. Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards, the Company's net earnings and net earnings per share for the year ended December 31, 2002 would have been the pro forma amounts indicated below:

	2004	2003 (Restated – note 3)
Net earnings		
As reported	\$3,301	\$2,172
Pro forma	\$3,260	\$2,146
Net earnings per common share – basic		
As reported	\$0.08	\$0.07
Pro forma	\$0.08	\$0.07
Net earnings per common share – diluted		
As reported	\$0.08	\$0.07
Pro forma	\$0.07	\$0.07

For options granted after January 1, 2003, the Company follows the fair value method.

The weighted average fair market value of options granted in the year ended March 31, 2004 is \$1.08 per option. The fair market of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions:

	2004	2003
Risk-free interest rate	4.50%	4.50%
Estimated hold period prior to exercise (years)	5	5
Volatility in the price of the Company's common shares	15%	38%
Dividend per share	\$0.00	\$0.00

8. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are based on the Company's net ownership in wells and facilities and management's estimate of costs to abandon and reclaim those wells and facilities as well as an estimate of the future timing of the costs to be incurred.

The Company has estimated the present value of its total asset retirement obligations to be \$7.9 million at March 31, 2004 based on a total future liability of \$21.1 million. Payments to settle asset retirement obligations occur over the operating lives of the underlying assets, estimated to be from zero to 50 years, with the majority of costs incurred between 2010 and 2026. Estimated cash flows have been discounted at the Company's credit-adjusted risk free rate of 8 percent and an inflation rate of 2.0 percent.

	Three months ended March 31,		Year ended December 31,
	2004	2003	2003
Asset retirement obligations, beginning of period	6,923	3,155	3,155
Liabilities incurred during period	879	699	3,626
Liabilities settled during period	(88)	(41)	(348)
Accretion	152	75	490
Asset retirement obligations, end of period	7,866	3,888	6,923

9. FINANCIAL INSTRUMENTS

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

a) Commodity Price Risk Management

Financial instruments are entered into by the Company to protect the downside prices received on the sale of a portion of its crude oil and natural gas production. The agreements entered into are forward transactions providing the Company with a range of fixed prices on the commodities sold. Petroleum and natural gas revenue for the three months ended March 31, 2004 include losses of \$0.2 million (2003 - \$1.3 million loss) on those transactions.

The following contracts were outstanding as at March 31, 2004:

Commodity	Type	Term	Volume	Price	Index
Natural gas	Fixed	April 2004 – September 2004	4,000 GJ's/d	\$5.88/GJ	AECO
Natural gas	Fixed	October 2004 – December 2004	1,333 GJ's/d	\$5.88/GJ	AECO
Crude oil	Fixed	April 2004 – June 2004	600 bbls/d	US \$27.50/bbl	WTI
Crude oil	Fixed	July 2004 – September 2004	600 bbls/d	US \$29.17/bbl	WTI
Crude oil	Fixed	October 2004 – December 2004	600 bbls/d	US \$28.70/bbl	WTI

The estimated fair value at March 31, 2004 of these transactions, had the contracts been settled at that time, would be a loss of \$1.5 million.

10. SUBSEQUENT EVENT

Recent APF Offer

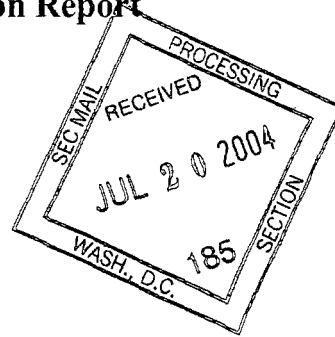
On April 7, 2004, APF Energy Inc., APF Energy Trust (collectively, the "Offeror") and Great Northern announced that the Offeror had agreed to make an offer to acquire all of the outstanding common shares of Great Northern Exploration Ltd. and all common shares which may become outstanding on the exercise of the outstanding stock options, on the basis of, at the election of the holder, either:

- a) \$5.05 cash for each Common Share; provided that not more than \$55.2 million in cash shall be payable in the aggregate under the Offer, with the balance being paid in trust units ("APF Units") of APF Energy Trust at an exchange rate of 0.414614 Trust Units per Common Share (the "Cash Alternative");
- b) 0.414614 Trust Units for each GNEL Share (the "Trust Unit Alternative"); or

subject to the stated maximum, any combination thereof (the "Offer") as more particularly described and upon the terms and subject to the conditions set forth in the "Offering Circular" dated April 26, 2004.

The Offer is scheduled to expire on June 1, 2004.

**APF Energy Trust
Form 51-102 F4
Revised Business Acquisition Report**



Item 1 Identity of Company

1.1 Name and Address of Company

APF Energy Trust (the "Trust")
2100, 144 – 4th Avenue S.W.
Calgary, Alberta
T2P 3N4

1.2 Executive Officer

For further information contact Steven Cloutier, President of APF Energy Inc. by telephone at (403) 294-1000 or by fax at (403) 294-1074.

Item 2 Details of Acquisition

2.1 Nature of Business Acquired

Pursuant to the offer by APF Energy Inc. and the Trust to acquire all of the issued and outstanding common shares (the "Shares") of Great Northern Exploration Ltd. ("Great Northern") dated April 26, 2004 (the "Offer"), 41,694,977 Shares, representing approximately 95% of the Shares were acquired pursuant to the Offer.

Holders of the Shares were entitled to elect, for each Share, 0.414614 of a trust unit of the Trust ("Units") or \$5.05 in cash, subject to an aggregate maximum of \$55,190,101.65 and proration.

A total of 33,053,803 Shares were tendered for cash, while 6,509,874 Shares were tendered for Units. As a result, those Great Northern shareholders electing to receive cash for all, or a portion, of their holdings received \$1.573252 per Share, with the balance being satisfied by the issuance of Units on the basis of 0.285447 Units per Share. There was no proration for those Great Northern shareholders who elected to receive all Units. A total of 2,131,300 Shares were also purchased by APF Energy Inc. in the open market.

APF acquired all remaining Shares of Great Northern by way of a compulsory acquisition transaction pursuant to the *Business Corporations Act* (Alberta).

APF Energy Inc., Great Northern and a wholly-owned subsidiary of Great Northern were amalgamated on June 9, 2004 and the amalgamated company is named "APF Energy Inc.".

Great Northern was a publicly traded junior oil and gas company listed on the Toronto Stock Exchange, with revenues derived primarily from oil and gas properties in Alberta and Saskatchewan. Great Northern's operations were primarily concentrated in the areas of Great Provost in East Central Alberta, the Robsart area of Southwest Saskatchewan and in the West Central Alberta area.

Based on Great Northern's reserve report effective December 31, 2003, Great Northern's total proved reserves were 11,781 thousand barrels of oil equivalent ("mboe"), and proved plus probable reserves were 17,074 mboe, in each case using forecast prices and costs.

2.2 Date of Acquisition

June 4, 2004

2.3 Consideration

As set forth in item 2.1, consideration for the acquisition of the Shares of Great Northern was a combination of a maximum of \$55 million in cash and Units. A maximum of 12,712,645 Units may be issued, if all holders of Shares that will be acquired on the compulsory acquisition, elect Units. Aggregate consideration for the transaction was \$285 million (before transaction costs), which includes the assumption of \$65 million of debt of Great Northern.

2.4 Effect on Financial Position

On completion of the acquisition of Great Northern, APF Energy Inc., Great Northern and 905698 Alberta Ltd., a wholly-owned subsidiary of Great Northern, were amalgamated to form "APF Energy Inc.". It is estimated that the combined entity will have 2004 average annual production of 15,850 boe/day, based on 12 months of production of APF Energy and on seven months of production of Great Northern.¹

A summary of the estimated effects of the acquisition of Great Northern on the Trust and the information presented in the Trust's *Statement of Reserves Data and Other Oil and Gas Information* on Form 51-101F1 contained in the Trust's annual information form for the year ended December 31, 2003 is set forth below.

¹ "boes" as used in this document may be misleading, particularly if used in isolation. A boe conversion ratio for natural gas of 6 mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserves Data

The oil and natural gas reserves of APF Energy Inc. ("APF") and APF Energy Limited Partnership ("APF Partnership") were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ") effective January 1, 2004. The coalbed methane reserves of Tika Energy Inc. ("Tika"), a wholly owned subsidiary of APF were evaluated by McDaniel & Associates Consultants Ltd. and were consolidated with the GLJ evaluated properties to generate corporate total forecasts. The oil and natural gas reserves of Great Northern were evaluated by GLJ effective December 31, 2003.

Following is a summary of the oil and natural gas reserves and the value of future net revenues of APF, APF Partnership, Tika and Great Northern as evaluated by GLJ (except with respect to Tika, as noted above). The pricing used in the forecast and constant price evaluations is also set forth below.

It should not be assumed that the estimated present worth values of net production revenue contained in the following tables represents the fair market value of the reserves. All evaluations have been stated prior to any provision for income taxes. There is no assurance that the price and cost assumptions contained in the constant price and cost and escalating price and cost assumption cases will be attained and variances could be material.

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

CONSTANT PRICES AND COSTS

Reserves Category	Constant Reserves									
	Natural Gas		Light & Medium Oil		Heavy Oil		Natural Gas Liquids		Total	
	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mboe)	Net (mboe)
Proved										
Developed Producing	95,681	79,224	16,138	14,313	1,069	998	1,694	1,239	34,848	29,755
Developed Non-Producing	10,464	8,314	912	849	668	633	339	262	3,662	3,131
Undeveloped	4,567	3,632	2,851	2,514	207	186	176	125	3,996	3,431
Total Proved	110,712	91,170	19,901	17,676	1,944	1,817	2,209	1,626	42,506	36,317
Probable	42,137	34,679	7,240	6,379	1,287	1,174	560	421	16,110	13,754
Total Proved plus Probable	152,849	125,849	27,141	24,055	3,231	2,991	2,769	2,047	58,616	50,071

Columns may not add due to rounding.

Reserves Category	NET PRESENT VALUE OF FUTURE NET REVENUE				
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
	0% (MMS)	5% (MMS)	10% (MMS)	15% (MMS)	20% (MMS)
Proved					
Developed Producing	664.0	523.7	438.3	380.5	338.5
Developed Non-Producing	74.5	51.5	40.5	33.9	29.4
Undeveloped	67.8	44.9	31.5	23.1	17.5
Total Proved	806.2	620.0	510.4	437.6	385.5
Probable	286.6	187.4	136.6	105.6	84.8
Total Proved plus Probable	1,092.9	807.4	646.9	543.2	470.2

Columns may not add due to rounding.

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003**

FORECAST PRICES AND COSTS

Reserves Category	Constant Reserves									
	Natural Gas		Light & Medium oil		Heavy Oil		Natural gas liquids		Total	
	Gross (mmcf)	Net (mmcf)	Gross (mmbbl)	Net (mmbbl)	Gross (mmbbl)	Net (mmbbl)	Gross (mmbbl)	Net (mmbbl)	Gross (mboe)	Net (mboe)
Proved										
Developed Producing	94,437	78,158	15,406	13,685	978	919	1,670	1,225	33,793	28,855
Developed Non-Producing	10,481	8,312	923	860	624	592	341	264	3,634	3,101
Undeveloped	4,658	3,684	2,824	2,559	201	181	176	127	3,976	3,481
Total Proved	109,576	90,154	19,153	17,104	1,803	1,692	2,187	1,616	41,403	35,437
Probable	41,286	33,979	6,999	6,199	1,205	1,105	557	420	15,643	13,387
Total Proved plus Probable	150,862	124,133	26,152	23,303	3,008	2,797	2,744	2,036	57,046	48,824

Columns may not add due to rounding.

Reserves Category	NET PRESENT VALUE OF FUTURE NET REVENUE				
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
	0% (MMS)	5% (MMS)	10% (MMS)	15% (MMS)	20% (MMS)
Proved					
Developed Producing	465.2	385.9	333.0	295.2	266.8
Developed Non-Producing	56.5	39.1	31.1	26.3	23.0
Undeveloped	44.3	28.5	19.1	13.4	9.4
Total Proved	565.9	453.5	383.2	334.9	299.2
Probable	196.1	128.4	93.3	71.6	57.0
Total Proved plus Probable	762.0	581.9	476.5	406.4	356.2

Columns may not add due to rounding.

Notes:

- (1) The net present value of future net revenues has been presented only on a before income taxes basis. Given the structure of the Trust, the values after income taxes would be the same.
- (2) "Gross" reserves are the company working interest share before deduction of royalties and without including royalty interests.
- (3) "Net" reserves are the company working interest share after deduction of royalty obligations, plus royalty interests.
- (4) ARTCs associated with eligible interests have been included.
- (5) The effect on projected revenues from hedging activity has not been included.
- (6) Processing income was included as "Other Income" in the corporate total economic forecast.
- (7) Provisions for the abandonment and reclamation of only those company wells assigned reserves by GLJ were included.
- (8) General and administrative costs and overhead recovery were not included.
- (9) The constant price analysis was performed by rerunning the evaluation database using fixed last day (December 31, 2003) posted pricing and no cost escalations.
- (10) Subsequent to December 31, 2003, Great Northern acquired producing properties for \$23 million, complimentary to its existing Innisfail area, information relating to which was disclosed in a press release of Great Northern dated February 2, 2004. Reserves values for Great Northern summarized in the press release of the Trust dated April 7, 2004 announcing the Offer, included the acquisition made by Great Northern in February, 2004. The reserves and net revenue from reserves from such acquisition are not included in the tables above.
- (11) "mmcf" means million cubic feet; "mmbbl" means thousand barrels.

**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\$)	WELL ABANDONMENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Reserves	1,548,896	247,472	425,822	32,420	36,892	806,291	46,406	759,885
Proved Plus Probable Reserves	2,114,972	343,299	565,143	74,559	39,091	1,092,879	85,140	1,007,739

**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)	217,906
	Heavy Oil (including solution gas and other by-products)	18,614
	Natural Gas (including by-products but excluding solution gas from oil wells)	270,785
	Coalbed Methane	3,080
Total Proved		510,385
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	279,351
	Heavy Oil (including solution gas and other by-products)	27,862
	Natural Gas (including by-products but excluding solution gas from oil wells)	335,711
	Coalbed Methane	4,030
Total Proved plus Probable		646,954

**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\$)	WELL ABANDONMENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Reserves	1,297,800	201,004	452,084	33,508	45,232	565,972	24,599	541,374
Proved Plus Probable Reserves	1,773,256	277,267	608,928	76,134	48,938	761,990	50,103	711,888

**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) Heavy Oil (including solution gas and other by-products) Natural Gas (including by-products but excluding solution gas from oil wells) Coalbed Methane	149,365 13,536 218,183 2,191
Total Proved		383,275
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products) Heavy Oil (including solution gas and other by-products) Natural Gas (including by-products but excluding solution gas from oil wells) Coalbed Methane	191,357 20,808 261,225 3,079
Total Probable		476,470

Pricing Assumptions

The following tables set forth the benchmark reference prices and pricing assumptions used in preparing the reserves data and, in the case of forecast prices and costs, the inflation rate assumptions.

**SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2003**

CONSTANT PRICES AND COSTS

Crude Oil and Natural Gas Prices

Year	Inflation %	Exchange Rate US\$/SCdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current US\$/bbl	Brent Blend Crude Oil FOB North Sea Then Current US\$/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current SCdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current SCdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current SCdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current SCdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars)			
									Spec Ethane SCdn/bbl	Edmonton Propane SCdn/bbl	Edmonton Butane SCdn/bbl	Edmonton Pentanes Plus SCdn/bbl
2003 (Year End)	0.0	0.7738	32.52	31.02	40.81	29.81	23.31	34.81	19.50	29.81	31.81	41.31

Constant Thereafter

Natural Gas and Sulphur

Year	US Gulf Coast Gas Price @ Henry Hub Then Current \$/mmbtu	Midwest Price@ Chicago Then Current \$/mmbtu	AECO-C Spot Then Current \$/mmbtu	Alberta Plant Gate			Saskatchewan Plant Gate			British Columbia		Sulphur FOB Vancouver SUS/LT	Alberta Sulphur at Plant Gate \$/CDn/LT	
				Spot Then Current \$/mmbtu	ARP \$/mmbtu	Aggregator \$/mmbtu	Alliance \$/mmbtu	SaskEnergy \$/mmbtu	Spot \$/mmbtu	Sumas Spot \$/mmbtu	CanWest Plant Gate \$/mmbtu			Spot Plant Gate \$/mmbtu
2003 (Year End)	5.77	5.86	6.09	5.83	5.73	5.43	5.83	5.88	5.98	5.49	5.43	5.78	\$9.50	35.00

Constant Thereafter

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.

The plant gate price represents the price before raw gas gathering and processing changes are deducted.

Spot refers to weighted average one month price.

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

FORECAST PRICES AND COSTS

Year	OIL ⁽¹⁾				Natural Gas ⁽¹⁾ AECO Gas Price (\$/Cdn/mmbtu)	Edmonton Pentanes Plus (\$/Cdn/bbl)	Inflation Rates ⁽¹⁾ (%/Year)	Exchange Rate ⁽²⁾ (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Hardisty Heavy 12° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)				
Forecast								
2004	29.00	37.75	20.25	31.75	5.85	38.25	1.5	0.75
2005	26.00	33.75	20.25	28.75	5.15	34.25	1.5	0.75
2006	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
2007	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
2008	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
2009-2014	25.00	32.50	21.00	28.50	5.00	33.00	1.5	0.75
Thereafter	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	1.5	0.75

Notes:

- (1) Inflation rates for forecasting prices and costs.
- (2) Exchange rates used to generate the benchmark reference prices in this table.
- (3) The price forecast is the GLJ standard price forecast effective January 1, 2004.

Additional Information Relating to Reserves Data*Undeveloped Reserves*

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, undeveloped reserves are scheduled to be developed within the next two years of the effective date. Capital expenditures to develop proved undeveloped reserves are estimated at \$14.511 million in 2004 and \$4.680 million in 2005.

Properties with no Attributed Reserves

Great Northern had undeveloped land holdings at December 31, 2003 of 374,914 gross acres (140,995 net). Rights to explore and develop approximately 48,000 net acres are expected to expire by December 31, 2004.

Oil and Gas Wells

The acquisition of Great Northern increases the number of wells in which APF has an interest as follows: oil wells – 229 gross producing (111 net); 233 gross shut-in (133 net); natural gas wells – 270 gross producing (97 net) and 227 gross shut-in (73 net), as at December 31, 2003.

Significant Factors or Uncertainties

There are no significant factors or uncertainties that may impact the reserves and values arising from the acquisition of Great Northern, other than the risks inherent in the oil and gas industry generally, the risks associated with the Trust's corporate and other acquisitions and other risks as identified in the Trust's annual information form for the year ended December 31, 2003.

Future Development Costs

The following table sets forth development costs deducted in the estimation of future net revenue attributable to the reserve categories noted below.

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

Reserves Category	Development Costs Deducted in Estimating Future Net Revenues													
	Development Costs – Undiscounted (\$000)							Development Costs - 10% Discount Rate						
	2004	2005	2006	2007	2008	Thereafter	Total	2004	2005	2006	2007	2008	Thereafter	Total
Total Proved (Constant prices and costs)	18,322	5,000	3,569	626	901	4,002	32,423	17,469	4,334	2,812	448	587	1,650	27,301
Total Proved (Forecast prices and costs)	18,327	5,127	3,679	655	953	4,767	33,507	17,474	4,444	2,899	469	620	1,850	27,757
Total Proved plus Probable (Forecast prices and costs)	43,154	15,766	7,664	2,621	1,233	5,696	76,134	41,146	13,666	6,039	1,878	803	2,181	65,712

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment and reclamation costs, based on actual costs incurred to date for abandonment and reclamation activities, for the next three years are \$2.06 million in 2004, \$1.51 million in 2005 and \$1.61 million in 2006.

Tax Horizon

As a result of the Trust's tax efficient structure, annual taxable income is transferred from its operating entities to the Trust, and from the Trust to its unitholders. This is primarily accomplished through the deduction of the royalties on underlying oil and gas properties held by

the Trust's operating subsidiaries. Therefore, it can be expected that no income tax liability will be incurred by the Trust for as long as the organization maintains this corporate tax structure.

Production Estimates

The following table sets out the gross volume of estimated production for the year ended December 31, 2004, from the Total Proved Reserves based on constant prices and costs.

	Light and Medium Crude Oil bbl/d	Heavy Oil bbl/d	Natural Gas mcf/d	NGLs bbl/d	Boe boe/d
Total Proved	6,646	1,107	57,338	941	18,251

Note:

(1) The above estimated production reflects 12 months of production for both APF and Great Northern.

2.5 Prior Valuations

None.

2.6 Parties to Transaction

Not applicable.

2.7 Date of Report

June 29, 2004.

Item 3 Financial Statements

The unaudited pro forma consolidated financial statements of the Trust are attached as Schedule A hereto.

The audited annual consolidated financial statements of Great Northern for the years ended December 31, 2003 and 2002 are attached as Schedule B hereto. The auditors for Great Northern have not provided a formal consent for the inclusion, in this Business Acquisition Report, of their audit report on such annual consolidated financial statements of Great Northern.

The unaudited consolidated interim financial statements of Great Northern for the three month periods ended March 31, 2004 and 2003 are attached as Schedule C hereto.

SCHEDULE A

PRO-FORMA CONSOLIDATED FINANCIAL STATEMENTS THREE MONTHS ENDED MARCH 31, 2004

Compilation Report

**To the Trustee of APF Energy Trust
and to the Directors of APF Energy Inc.**

We have read the accompanying unaudited pro-forma consolidated balance sheet as at March 31, 2004 and the unaudited pro-forma statement of operations of APF Energy Trust (the "Trust") for the three months ended March 31, 2004, and have performed the following procedures.

1. Compared the figures in the columns captioned "APF Energy Trust" and "Great Northern Exploration Ltd." to the unaudited financial statements of the applicable entity as at or for the three months ended March 31, 2004, and found them to be in agreement.
2. Made inquiries of certain officials of the Trust who have responsibility for financial and accounting matters about:
 - (a) the basis for determination of the pro-forma adjustments; and
 - (b) whether the pro-forma financial statements comply as to form in all material respects with *Securities Acts* of the various Provinces of Canada (the "Acts").

The officials:

- (a) described to us the basis for determination of the pro-forma adjustments, and
 - (b) stated that the pro-forma statements comply as to form in all material respects with the Acts.
3. Read the notes to the pro-forma statements, and found them to be consistent with the basis described to us for determination of the pro-forma adjustments.
4. Recalculated the application of the pro-forma adjustments to the aggregate of the amounts in the columns captioned "APF Energy Trust" and "Great Northern Exploration Ltd." as at and for the three months ended March 31, 2004 and found the amounts in the columns captioned "Total" to be arithmetically correct.

A pro-forma financial statement is based on management assumptions and adjustments which are inherently subjective. The foregoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with respect to management's assumptions, the pro-forma adjustments, and the application of the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro-forma financial statements, and we therefore make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

(Signed) *"PricewaterhouseCoopers LLP"*
Chartered Accountants

Calgary, Alberta
June 28, 2004

APF Energy Trust
 Pro-Forma Consolidated Balance Sheet
 (Unaudited)
March 31, 2004

2

	APF Energy Trust March 31, 2004	Great Northern Exploration Ltd. March 31, 2004	Adjustments (Note 2(a))	Total
	(\$000s)			
ASSETS				
Current assets				
Cash	739	—		739
Accounts receivable	28,498	11,473		39,971
Deferred derivative loss	1,178	—		1,178
Other current assets	3,703	546		4,249
	34,118	12,019		46,137
Asset retirement fund	2,693	—		2,693
Goodwill	48,230	—	78,655	126,885
Property, plant and equipment	409,923	160,448	118,436	688,807
	494,964	172,467	197,091	864,522
LIABILITIES				
Current liabilities				
Bank debt	—	45,596	(45,596)	—
Accounts payable and accrued liabilities	28,785	21,916		50,701
Derivative liabilities	4,443	—		4,443
Cash distribution payable	6,943	—		6,943
	40,171	67,512	(45,596)	62,087
Future income taxes	58,614	9,641	47,590	115,845
Long-term debt	55,000	—	127,705	182,705
Asset retirement obligations	22,187	7,866		30,053
	175,972	85,019	129,699	390,690
UNITHOLDERS' EQUITY				
Unitholders' investment account	386,003	72,859	81,981	540,843
Contributed surplus	1,325	251	(251)	1,325
Accumulated earnings	88,022	14,338	(14,338)	88,022
Accumulated cash distributions	(199,192)	—	—	(199,192)
Convertible debentures	46,277	—		46,277
Accumulated interest on convertible debentures	(3,443)	—		(3,443)
	318,992	87,448	67,392	473,832
	494,964	172,467	197,091	864,522

APF Energy Trust
 Pro-Forma Consolidated Statement of Operations
 (Unaudited)
March 31, 2004

3

	APF Energy Trust Three Months Ended March 31, 2004	Great Northern Exploration Ltd. Three Months Ended March 31, 2004	Adjustments (Note 2(b))	Total
	(\$000s except per unit amounts)			
Revenue				
Oil and natural gas	46,355	19,529		65,884
Realized derivative loss – net	(1,027)			(1,027)
Non-cash derivate loss – net	(3,265)			(3,265)
Royalties expense, net of ARTC	(9,057)	(3,909)	(125) (vi)	(13,091)
Transportation	(865)	–		(865)
	32,141	15,620	(125)	47,636
Expenses				
Operating	8,910	3,892		12,802
General and administrative – net	1,839	304		2,143
Stock based compensation expense	257	–		257
Interest on long-term debt	977	538	1,026 (ii)	2,541
Capital and other taxes	605	–	201 (v)	806
Depletion, depreciation and accretion	17,033	5,591	3,131 (i)(iv)	25,755
	29,621	10,325	4,359	44,305
Income before income taxes	2,520	5,295	(4,484)	3,331
Provision for income taxes (recovery)				
Current	–	94	(94) (v)	–
Future	(5,607)	1,900	(1,713) (iii)	(5,420)
Net income for the period	8,127	3,301	(2,677)	8,751
Net income per unit – basic	0.19			0.15
Net income per unit – diluted	0.19			0.15

1. Basis of Presentation

The pro-forma consolidated financial statements of APF Energy Trust (the "Trust"), which owns a 99% interest in certain oil and gas royalties, have been prepared by management to give effect to the purchase of Great Northern Exploration Ltd. ("GNEL"). GNEL was involved in oil and gas exploration, development and production in western Canada. The pro-forma consolidated financial statements have been prepared from information derived from the March 31, 2004 unaudited consolidated historical financial statements of the Trust and the March 31, 2004 unaudited financial statements of GNEL, and the assumptions set out in note 2 below.

The GNEL Shares were purchased by the Trust through a take-over bid which closed June 4, 2004. The pro-forma consolidated statement of operations gives effect to those transactions as if they occurred January 1, 2004. The pro-forma consolidated balance sheet gives effect to those transactions at March 31, 2004.

The pro-forma consolidated financial statements do not give effect to any transaction that does not meet the significant test rules as defined by various securities regulators.

The pro-forma consolidated financial statements may not be indicative of the financial position or the results of operations or royalty distribution of the Trust which will be obtained upon completion of the acquisition of GNEL (the "Acquisition"). In preparing the pro-forma consolidated financial statements, no adjustments have been made to reflect any operating or administrative cost savings that may result from the operations of the consolidated assets.

Accounting policies used in the preparation of the pro-forma financial statements are in accordance with those disclosed in the Trust's unaudited financial statements as at and for the three months ended March 31, 2004. The acquisition of GNEL has been accounted for as a business acquisition. In the opinion of management, the pro-forma financial statements include all adjustments necessary for fair presentation.

The pro-forma statements should be read in conjunction with the Trust's unaudited consolidated financial statements as at and for the three months ended March 31, 2004 and the unaudited financial statements of GNEL for the three months ended March 31, 2004.

The Trust is an open-ended investment trust under the laws of the Province of Alberta.

The royalty interests (the "Royalty") in producing oil and natural gas properties acquired from APF Energy Inc. and APF Energy Limited Partnership (collectively "APF") effectively transfer 99% of the economic interest in such properties to the Unitholders. The Royalty constitutes a royalty interest in the oil and natural gas properties owned by APF but does not confer ownership in the underlying resource properties. APF is permitted to borrow funds to finance the purchase of additional properties and tangibles, for capital expenditures or for other financial obligations or encumbrances in respect of the properties should the properties not generate sufficient income to repay debt. The Trust is entitled to 99% of the production and incidental revenues from the properties less all costs and expenses in respect of the properties, taxes in respect of the properties, general and administrative costs of APF and the Royalty and debt service charges (including principal repayments). The Trust is required to reimburse APF for Crown royalties and charges in respect of production allocable to the Royalty.

2. Pro-forma adjustments and assumptions

- (a) The pro-forma consolidated balance sheet of the Trust as at March 31, 2004, has been prepared as if the following transactions had been completed as of the balance sheet date:

GNEL ACQUISITION

The purchase by the Trust of 100% of the shares of GNEL for \$227,292,000 before adjustments and other costs is assumed to be paid 25% in cash with the balance in Trust Units, and is accounted for as a business combination and is allocated as follows:

	(000s)
Property plant and equipment	\$278,884
Goodwill	78,655
Current assets	12,019
Current liabilities	(21,916)
Bank debt	(55,253)
Asset retirement obligations	(7,866)
Future income taxes	(57,231)
Net	<u>\$227,292</u>

Paid by:	
Trust Units (12,712,645 Trust Units)	154,840
Bank Indebtedness	65,353
Transaction costs including severance	<u>7,099</u>
	<u>\$227,292</u>

The current bank debt of GNEL has been reclassified to long term debt to be consistent with APF's credit facilities.

- (b) The pro-forma consolidated statement of operations has been prepared as if the proposed transactions took place on January 1, 2004.
- (i) The purchase price allocated to the GNEL assets are amortized on a unit of production basis;
 - (ii) the interest for the change of bank debt related to the Acquisition has been recorded at 5% per annum with no deemed principal repayments;
 - (iii) current taxes were adjusted to account for income taxes as if the income from the acquisitions subject to the royalty calculation was in effect January 1, 2004. The taxes on the incremental income are assumed to be passed to the Unitholders through the royalty calculation. The future income tax expense has been adjusted to reflect the impact on earnings of the transactions at the maximum statutory rate;
 - (iv) site restoration in the case of GNEL has been reclassified from depletion and amortization;
 - (v) a Saskatchewan surtax is applied to certain properties and capital taxes have been reclassified out of income taxes;
 - (vi) Alberta Royalty Tax Credit was adjusted to reduce the amount to the maximum allowable for the period;
 - (vii) the net income on a per unit basis is based on 50,093,245 Trust Units assumed outstanding for the period (54,410,228 diluted).

3. Unitholders' equity

The authorized unit capital of the Trust consists of 500,000,000 Trust Units of which 34,074,240 Trust Units were outstanding at December 31, 2003, with 4,765,000 Trust Units issued under the January 27, 2004 prospectus and the assumption that 12,712,645 Trust Units were issued to the shareholders of GNEL. Pursuant to a June 26, 2003 prospectus, the Trust sold 50,000, 9.40% Convertible Unsecured Subordinated Debentures at a price of \$1,000 per Debenture. The maturity date is July 31, 2008. The Debentures are convertible at the holder's option into fully paid Trust Units at a conversion price of \$11.25 per Trust Unit, being a conversion rate of 88.8889 Trust Units for each \$1,000 principal amount of Debentures. The Trust is also authorized to issue an unlimited number of Special Voting Units.

4. GNEL Acquisition

On April 6, 2004, APF Energy and GNEL entered into an agreement whereby APF Energy agreed to acquire GNEL at a price of \$5.05 per share, payable at the option of the GNEL shareholders in cash for a maximum of 25% of the Purchase Price, or in Trust Units of the Trust, based on an exchange ratio of 0.414614 Trust Units for each GNEL Share. On June 4, 2004, APF Energy took up all of the GNEL shares tendered to the offer to acquire all of the shares of GNEL.

The pro-forma consolidated statement of operations have been prepared based on the fact that the GNEL shareholders elected for the maximum cash.

**PRO-FORMA CONSOLIDATED FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2003**

Compilation Report

**To the Trustee of APF Energy Trust
and to the Directors of APF Energy Inc.**

We have read the accompanying unaudited pro-forma statement of operations of APF Energy Trust (the "Trust") for the year ended December 31, 2003, and have performed the following procedures.

1. Compared the figures in the columns captioned "APF Energy Trust" and "Great Northern Exploration Ltd." to the audited financial statements of the applicable entity as at or for the year ended December 31, 2003, and found them to be in agreement.
2. Compared the figures in the columns captioned "Hawk Oil Inc." and "Nycan Energy Corp." to the unaudited financial statements of the applicable entity for the one month ended January 31, 2003 and for the four months ended April 30, 2003, respectively, and found them to be in agreement.
3. Made inquiries of certain officials of the Trust who have responsibility for financial and accounting matters about:
 - (a) the basis for determination of the pro-forma adjustments; and
 - (b) whether the pro-forma financial statements comply as to form in all material respects with *Securities Acts* of the various Provinces of Canada (the "Acts").

The officials:

- (a) described to us the basis for determination of the pro-forma adjustments, and
 - (b) stated that the pro-forma statements comply as to form in all material respects with the Acts.
4. Read the notes to the pro-forma statements, and found them to be consistent with the basis described to us for determination of the pro-forma adjustments.
5. Recalculated the application of the pro-forma adjustments to the aggregate of the amounts in the columns captioned "APF Energy Trust, Hawk Oil Inc., Nycan Energy Corp. and Great Northern Exploration Ltd." for the year ended December 31, 2003 and found the amounts in the columns captioned "Total" to be arithmetically correct.

A pro-forma financial statement is based on management assumptions and adjustments which are inherently subjective. The foregoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with respect to management's assumptions, the pro-forma adjustments, and the application of the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro-forma financial statements, and we therefore make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

(Signed) "PricewaterhouseCoopers LLP"
Chartered Accountants

Calgary, Alberta
June 28, 2004

Pro-Forma Consolidated Statement of Operations
(Unaudited)
December 31, 2003

	APF Energy Trust Year Ended December 31, 2003	Hawk Oil Inc. One Month Ended January 31, 2003	Nycan Energy Corp. Four Months Ended April 30, 2003	Great Northern Exploration Ltd. Year Ended December 31, 2003	Adjustments (Note 2)	Total
(\$000s except per unit amounts)						
Revenue						
Oil and natural gas	163,532	3,066	6,423	51,317		224,338
Royalties expense, net of ARTC	(32,473)	(419)	(1,257)	(9,928)		(44,577)
Other operating revenue	1,925	—	62	—	(500) (vi)	1,987
	132,984	2,647	5,229	41,389	(500)	181,748
Expenses						
Operating	32,370	670	979	9,617		43,636
General and administrative - net	10,023	1,864	2,976	1,363	(2,160) (vii)	14,066
Stock based compensation expense	1,241					1,241
Interest on long-term debt	4,171	25	100	1,172	(381) (ii)	5,087
Capital and other taxes	2,720				534 (v)	3,254
Depletion and amortization	50,417	443	1,155	12,021	11,950 (i)(iv)	75,986
Site restoration	3,327				542 (iv)	3,869
	104,269	3,003	5,210	24,173	10,485	147,139
Operating income	28,715	(356)	19	17,216	(10,985)	34,609
Provision for income taxes (recovery)						
Current	—	5	18	306	204 (iii)	—
Future	(14,333)	(50)	25	6,405	(534) (v) (4,209) (iii)	(12,163)
Net income for the period	43,048	(311)	(24)	10,505	(6,446)	46,772
Net income per unit - basic	1.32					0.87
Net income per unit - diluted	1.21					0.87

1. Basis of Presentation

The pro-forma consolidated financial statements of APF Energy Trust (the "Trust"), which owns a 99% interest in certain oil and gas royalties, have been prepared by management to give effect to the purchase of Hawk Oil Inc. ("Hawk"), Nycan Energy Corp. ("Nycan") and Great Northern Exploration Ltd. ("GNEL"). Hawk, Nycan and GNEL were involved in oil and gas exploration, development and production in western Canada. The pro-forma consolidated financial statements have been prepared from information derived from the December 31, 2003 audited consolidated historical financial statements of the Trust, the one month January 31, 2003 unaudited financial statements of Hawk, the four months ended April 30, 2003 unaudited financial statements of Nycan, the December 31, 2003 audited financial statements of GNEL, and the assumptions set out in note 2 below.

The Hawk shares were purchased by the Trust through a take-over bid, which closed February 5, 2003. The Nycan shares were purchased by the Trust through a take-over bid, which closed April 28, 2003. The GNEL Shares were purchased by the Trust through a take-over bid, which closed June 4, 2004. The pro-forma consolidated statement of operations gives effect to those transactions as if they occurred January 1, 2003. The pro-forma consolidated balance sheet gives effect to those transactions at December 31, 2003.

The pro-forma consolidated financial statements do not give effect to any transaction that does not meet the significant test rules as defined by various securities regulators.

The pro-forma consolidated financial statements may not be indicative of the financial position or the results of operations of the Trust which will be obtained upon completion of the acquisition of GNEL (the "Acquisition"). In preparing the pro-forma consolidated financial statements, no adjustments have been made to reflect any operating or administrative cost savings that may result from the operations of the consolidated assets.

Accounting policies used in the preparation of the pro-forma financial statements are in accordance with those disclosed in the Trust's audited financial statements as at and for the year ended December 31, 2003. The acquisition of Hawk, Nycan and GNEL have been accounted for as business acquisitions. In the opinion of management, the pro-forma financial statements include all adjustments necessary for fair presentation.

The pro-forma statements should be read in conjunction with the Trust's consolidated financial statements as at and for the year ended December 31, 2003, the unaudited financial statements of Hawk for the one month ended January 31, 2003, the unaudited financial statements of Nycan for the three months ended March 31, 2003 and the audited financial statements of GNEL for the year ended December 31, 2003.

The Trust is an open-ended investment trust under the laws of the Province of Alberta.

The royalty interests (the "Royalty") in producing oil and natural gas properties acquired from APF Energy Inc. and APF Energy Limited Partnership (collectively "APF") effectively transfer 99% of the economic interest in such properties to the Unitholders. The Royalty constitutes a royalty interest in the oil and natural gas properties owned by APF but does not confer ownership in the underlying resource properties. APF is permitted to borrow funds to finance the purchase of additional properties and tangibles, for capital expenditures or for other financial obligations or encumbrances in respect of the properties should the properties not generate sufficient income to repay debt. The Trust is entitled to 99% of the production and incidental revenues from the properties less all costs and expenses in respect of the properties, taxes in respect of the properties, general and administrative costs of APF and the Royalty and debt service charges (including principal repayments). The Trust is required to reimburse APF for Crown royalties and charges in respect of production allocable to the Royalty.

2. Pro-forma adjustments and assumptions

The pro-forma consolidated statement of operations has been prepared as if the proposed transactions took place on January 1, 2003.

- (i) The purchase price allocated to the Hawk capital assets, the Nycan capital assets and the GNEL assets are amortized on a unit of production basis;
- (ii) the interest for the change of bank debt related to the purchases after the use of cash from the issue of Trust Units, and from the issue of Debentures pursuant to prospectuses, has been recorded at 5% per annum with no deemed principal repayments (see note 3);

- (iii) current taxes were adjusted to account for income taxes as if the income from the acquisitions subject to the royalty calculation was in effect January 1, 2003. The taxes on the incremental income are assumed to be passed to the Unitholders through the royalty calculation. The future income tax expense has been adjusted to reflect the impact on earnings of the transactions at the maximum statutory rate;
- (iv) site restoration in the case of Hawk, Nycan, and GNEL has been reclassified from depletion and amortization;
- (v) a Saskatchewan surtax is applied to certain properties and capital taxes have been reclassified out of income taxes;
- (vi) Alberta Royalty Tax Credit was adjusted to reduce the amount to the maximum allowable for the year;
- (vii) compensation costs in Nycan arising from the sale of the company have been eliminated;
- (viii) the net income on a per unit basis is based on 48,447,738 Trust Units assumed outstanding for the period (52,875,738 diluted).

3. Unitholders' equity

The authorized unit capital of the Trust consists of 500,000,000 Trust Units of which 22,942,417 Trust Units were outstanding at December 31, 2002, with additional 3,990,461 Trust Units issued as part of the settlement for the Hawk shares, 1,342,004 Trust Units issued as part of the settlement for the CanScot Shares, 5,300,000 Trust Units issued under the March 19, 2003 prospectus, 4,765,000 Trust Units issued under the January 27, 2004 prospectus and the assumption that 13,593,621 Trust Units will be issued to the shareholders of GNEL. Pursuant to the June 26, 2003 prospectus, the Trust sold 50,000, 9.40% Convertible Unsecured Subordinated Debentures at a price of \$1,000 per Debenture. The maturity date is July 31, 2008. The Debentures are convertible at the holder's option into fully paid Trust Units at a conversion price of \$11.25 per Trust Unit, being a conversion rate of 88.8889 Trust Units for each \$1,000 principal amount of Debentures. The Trust is also authorized to issue an unlimited number of Special Voting Units.

4. GNEL Acquisition

On April 6, 2004, APF Energy and GNEL entered into an agreement whereby APF Energy agreed to acquire GNEL at a price of \$5.05 per share, payable at the option of the GNEL shareholders in cash for a maximum of 25% of the Purchase Price, or in Trust Units of the Trust, based on an exchange ratio of 0.414614 Trust Units for each GNEL Share. On June 4, 2004 APF Energy took up all of the GNEL Shares tendered to the offer to acquire all of the shares of GNEL.

The pro-forma consolidated statement of operations has been prepared based on the fact that the GNEL shareholders elected for the maximum cash.

SCHEDULE B

MANAGEMENT'S
REPORT TO THE
SHAREHOLDERS

The accompanying consolidated financial statements of Great Northern Exploration Ltd. are the responsibility of management. The financial and operating information presented in this Annual Report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies disclosed in the notes to the financial statements and in accordance with generally accepted accounting principles in Canada. When necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.



James M. Saunders, P. Eng.
President & Chief Executive Officer



Jerry M. Savieba, C.A.
Vice President, Finance & Chief Financial Officer

March 18, 2004

CONSOLIDATED FINANCIAL STATEMENTS

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Great Northern Exploration Ltd. as at December 31, 2003 and 2002 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Chartered Accountant

Calgary, Canada

March 17, 2004

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEET

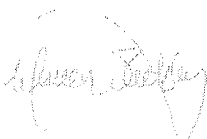
<i>As at December 31,</i>		2003	2002
		\$	\$
ASSETS			
<i>Current assets</i>			
Accounts receivable		12,456,000	5,192,000
Prepaid expenses		609,000	382,000
		13,065,000	5,574,000
Property and equipment	<i>(note 5)</i>	120,491,000	34,789,000
		133,556,000	40,363,000
LIABILITIES AND SHAREHOLDERS' EQUITY			
<i>Current liabilities</i>			
Accounts payable		19,754,000	10,656,000
Bank debt	<i>(note 6)</i>	38,555,000	5,107,000
		58,309,000	15,763,000
Future income taxes	<i>(note 11)</i>	8,097,000	—
Future site restoration	<i>(note 7)</i>	630,000	136,000
		67,036,000	15,899,000
<i>Shareholders' equity</i>			
Share capital	<i>(note 8)</i>	54,281,000	22,866,000
Contributed surplus	<i>(note 3)</i>	136,000	—
Retained earnings		12,103,000	1,598,000
		66,520,000	24,464,000
Subsequent events	<i>(note 14)</i>	133,556,000	40,363,000

On behalf of the Board of Directors:



James M. Saunders

Director



Warren Steckley

Director

(See accompanying notes to the consolidated financial statements)

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENT OF OPERATIONS AND RETAINED EARNINGS	<i>Year ended December 31.</i>	2003	2002
		\$	\$
	<i>Revenue</i>		
	Petroleum and natural gas sales	51,317,000	12,170,000
	Royalties, net	(9,928,000)	(1,965,000)
		41,389,000	10,205,000
	<i>Expenses</i>		
	Operating	9,617,000	2,626,000
	General and administrative	1,363,000	938,000
	Financial charges	1,172,000	220,000
	Depletion and depreciation	12,021,000	2,848,000
		24,173,000	6,632,000
	<i>Earnings before taxes</i>	17,216,000	3,573,000
	Capital taxes	306,000	116,000
	Future income taxes	6,405,000	1,663,000
		6,711,000	1,779,000
	<i>Net earnings</i>	10,505,000	1,794,000
	<i>Retained earnings (deficit), beginning of year</i>	1,598,000	(196,000)
	<i>Retained earnings, end of year</i>	12,103,000	1,598,000
	<i>Net earnings per share</i>		
	Basic	0.30	0.08
	Diluted	0.29	0.07

(See accompanying notes to the consolidated financial statements)

CONSOLIDATED
STATEMENT OF
CASH FLOW

<i>Year ended December 31,</i>	2003	2002
	\$	\$
<i>Cash flow related to the following activities</i>		
<i>Operating</i>		
Net earnings for the period	10,505,000	1,794,000
Items not affecting cash:		
Depletion and depreciation	12,021,000	2,848,000
Stock-based compensation (note 3)	136,000	—
Future income taxes	6,405,000	1,663,000
Cash flow from operations	29,067,000	6,305,000
Changes in non-cash operating working capital items	3,717,000	(706,000)
	32,784,000	5,599,000
<i>Financing</i>		
Change in bank debt	33,448,000	(8,888,000)
Share issuance, net	33,106,000	4,276,000
	66,554,000	(4,612,000)
<i>Cash available for investment activities</i>	99,338,000	987,000
<i>Investing</i>		
Property and equipment additions	(96,880,000)	(13,602,000)
Site restoration expenditures	(348,000)	—
Changes in non-cash investing working capital items	(2,110,000)	4,401,000
	(99,338,000)	(9,201,000)
<i>Change in cash</i>	—	(8,214,000)
<i>Cash, beginning of year</i>	—	8,214,000
<i>Cash, end of year</i>	—	—

(See accompanying notes to the consolidated financial statements)

YEAR ENDED DECEMBER 31, 2003

(tabular amounts in thousands of dollars, unless otherwise stated)

1. NATURE OF OPERATIONS

The shareholders of Great Northern Exploration Ltd. ("the Company"), approved a name change from Ascot Energy Resources Ltd. ("Ascot") and a share consolidation on the basis of one new share for every five existing common shares at the Annual and Special Meeting held on September 26, 2002. All share data including number of common shares outstanding, per share data and stock options outstanding have been adjusted to reflect the share consolidation.

On July 10, 2002, the Company acquired all the shares of Great Northern Exploration Ltd. ("Great Northern"), a private corporation. Great Northern was incorporated on August 9, 2001 and commenced active operations in September 2001.

The transaction has been accounted for as a reverse takeover of the Company by Great Northern. Accordingly, the results of operations for 2002 include those of Great Northern from the date of incorporation and those of the Company from the date of the acquisition to December 31, 2002.

The Company is engaged primarily in the exploration for and development and production of petroleum and natural gas in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

a) Basis of Presentation

The consolidated financial statements include the accounts of Great Northern Exploration Ltd. (the "Company") and its wholly-owned subsidiaries.

The Company's financial statements have been prepared in accordance with Canadian generally accepted accounting principles and reflect the following policies:

b) Petroleum and Natural Gas Operations

i) CAPITALIZED COSTS

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing oil and gas properties and related reserves are capitalized into a single Canadian cost center. Costs include land acquisition costs, geological and geophysical expenditures, costs of drilling both productive and non-productive wells, well equipment and certain other overhead expenditures related to exploration.

Gains or losses on the sale or disposition of oil and gas properties are not ordinarily recognized except under circumstances which result in a significant revision of depletion rates.

ii) DEPLETION AND DEPRECIATION

Petroleum and natural gas properties and related equipment, excluding undeveloped properties, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves. For purposes of this calculation, petroleum and natural gas reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes salvage values and the cost of unproved properties. Costs of acquiring and evaluating unproved properties are excluded from the depletion base until it is determined whether proved reserves are attributable to the properties or impairment occurs.

iii) CEILING TEST

In applying the full-cost method, the Company calculates a "ceiling test" to capitalized costs to ensure that such costs do not exceed future net revenues from estimated production of proven reserves, using prices and costs in effect at the Company's year end, less administrative, financing, site restoration and abandonment, and income tax expenses, plus the costs of unproven properties. Any reduction in value as a result of the ceiling test is charged to operations as an element of depletion and depreciation expense. Undeveloped land is evaluated for impairment at each balance sheet date.

c) *Joint Ventures*

Substantially all of the Company's exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

d) *Flow-through Shares*

The Company from time to time issues flow-through shares. Under these financing agreements, shares are issued at a fixed price with the resultant proceeds used to fund exploration and development work within a defined time period. The exploration and development expenditures funded by flow-through arrangements are renounced to investors in accordance with the appropriate tax legislation. A future tax liability is recorded and share capital is reduced by the estimated tax benefits transferred to shareholders.

e) *Future Site Restoration and Abandonment Costs*

Estimated future costs relating to site restoration and abandonment of petroleum and natural gas properties and related facilities are accrued on a unit of production basis over the estimated life of the proved reserves. Costs are based on engineering estimates, net of expected recoveries, based upon current prices and in accordance with current legislation, technology and industry standards.

f) *Future Income Taxes*

Income taxes are calculated using the liability method of tax allocation. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. The effect on future income tax liabilities or assets of a change in tax rates is recognized in net income in the period in which the change occurs.

g) *Stock-Based Compensation Plan*

The Company has a stock-based compensation plan which is described in note 9. As of January 1, 2003, the Company adopted a new accounting standard on stock-based compensation. Stock option expense is recorded as general and administrative expense for all options granted on or after January 1, 2003, with a corresponding increase recorded to contributed surplus. The expense related to options issued during 2002 is disclosed as proforma information in note 9.

The fair value of options granted are estimated at the date of the grant using the Black-Scholes valuation model. Upon the exercise of the stock options, consideration paid by employees or directors together with the amount previously recognized in contributed surplus, is credited to share capital.

h) *Per Share Amounts*

Per share amounts are calculated on the basis of the weighted average number of common shares outstanding during the period.

The treasury stock method of calculating diluted per share amounts is used whereby any proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

i) *Revenue Recognition*

Petroleum and natural gas sales are recognized as revenue at the time the respective commodities are delivered to purchasers.

j) *Financial Instruments*

Settlement of crude oil and natural gas swap agreements, which have been arranged as a hedge against commodity price, are reflected in revenues at the time of sale of the related hedged production.

k) *Measurement Uncertainty*

The amount recorded for depletion and depreciation of property and equipment, the provision for site restoration costs and the ceiling test calculation are based upon estimates of gross proved reserves, production rates, crude oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

3. **CHANGE IN
ACCOUNTING
POLICY**

Stock-Based Compensation Plan

In September 2003, the Canadian Institute of Chartered Accountants ("CICA") amended Handbook Section 3870 - "Stock-based Compensation and Other Stock-based Payments". Pursuant to new transitional rules approved by the CICA, the Company early adopted the amended standard on a prospective basis and now records stock-based compensation expense in the Consolidated Statement of Operations for all common share options granted to employees and directors on or after January 1, 2003. As a result of adopting this amended standard, net earnings for the year ended December 31, 2003 decreased by \$136 thousand and contributed surplus increased by an equal amount.

Common share options granted prior to January 1, 2003 do not result in a compensation expense and the Company continues to disclose the proforma earnings impact of related stock-based compensation expense for these options (note 9).

4. **BUSINESS
COMBINATION**

On July 10, 2002, the business transaction between Ascot and Great Northern was formally approved. This reverse takeover by Great Northern of Ascot resulted in Ascot issuing 6.5 common shares for each 1 share of Great Northern in which there were 14,052,000 Great Northern common shares issued and outstanding. Total shares issued pursuant to the business transaction were 91,338,000 or 18,267,600 common shares after the above mentioned share consolidation.

The Company acquired all of the shares of Great Northern and has accounted for the transaction as an acquisition of the Company by Great Northern.

Net assets acquired	\$
Property and equipment	20,573
Working capital	626
Future income tax asset	3,215
Long-term debt	(13,995)
Transaction costs	(2,167)
Purchase price - common share equity value	8,252

5. PROPERTY,
PLANT AND
EQUIPMENT

		Accumulated Depletion and Depreciation	Net Book Value
2003	Cost		
	\$	\$	\$
Petroleum and natural gas properties	134,644	14,219	120,425
Office equipment	88	22	66
	<u>134,732</u>	<u>14,241</u>	<u>120,491</u>

		Accumulated Depletion and Depreciation	Net Book Value
2002	Cost		
	\$	\$	\$
Petroleum and natural gas properties	37,457	2,702	34,755
Office equipment	47	13	34
	<u>37,504</u>	<u>2,715</u>	<u>34,789</u>

The Company has capitalized, as part of petroleum and natural gas properties, indirect exploration overhead relating to property acquisition, exploration and development activities of \$553 thousand for the year ended December 31, 2003 (2002 - \$147 thousand).

Undeveloped land costs of \$9.4 million (2002 - \$6.0 million) have been excluded from the amount subject to depletion and depreciation.

6. CREDIT FACILITIES

	2003	2002
	\$	\$
Prime rate advances	8,555	107
Bankers' acceptances	30,000	5,000
	<u>38,555</u>	<u>5,107</u>

Subsequent to December 31, 2003, the Company amended its demand revolving credit facility to a maximum of \$70 million. The credit facility bears interest at the lenders' prime rate or at the Bankers' Acceptance rate plus a stamping fee of 1.25%. The \$70 million borrowing base is subject to a semi-annual and annual review by the lender. The credit facility is secured by a first fixed and floating charge debenture in the amount of \$100 million covering all the Company's assets.

7. SITE
RESTORATION
AND
ABANDONMENTS

At December 31, 2003, total future removal and site restoration costs to be accrued over the life of the remaining proved reserves were estimated, net of recoveries, at \$7.7 million (2002 - \$2.1 million) of which \$630 thousand (2002 - \$136 thousand) has been accrued. This estimate is subject to change based on amendments to environmental laws and as new information concerning operations becomes available.

8. SHARE CAPITAL *a) Authorized*

Unlimited number of common voting shares

Unlimited number of preferred shares, issuable in series

b) Issued

	Number of Shares	Amount \$
Balance, December 31, 2001	17,065,100	11,890
Issued for cash	1,202,500	550
Acquisition of Ascot Energy Resources Ltd.	10,726,182	8,252
Exercise of stock options	110,500	85
Flow-through shares issued	1,379,400	4,000
Tax benefit renounced to shareholders	—	(1,705)
Share issue costs, net of tax effect	—	(206)
Balance, December 31, 2002	30,483,682	22,866
Issued on private placement	4,000,000	13,800
Issued on private placement	3,750,000	15,000
Exercise of stock options	125,000	142
Flow-through shares issued	1,100,000	6,050
Tax benefit renounced to shareholders	—	(2,456)
Share issue costs, net of future tax	—	(1,121)
Balance, December 31, 2003	39,458,682	54,281

In December 2003, 1,100,000 flow-through common shares were issued at a price of \$5.50 per share for gross proceeds of \$6.1 million. Under the terms of the flow-through agreement, the Company is required to expend \$6.1 million on qualifying crude oil and natural gas expenditures prior to December 31, 2004. As at December 31, 2003, the Company had incurred qualifying expenditures in the amount of \$0.6 million.

**9. STOCK-BASED
COMPENSATION**

The Company has implemented a Stock Option Plan for directors and employees. Options under the Plan vest over a four year period with 25% vesting upon each anniversary date of the grant. As of December 31, 2003, there were 3,001,250 common shares reserved for issuance to eligible participants. At December 31, 2003, 3,405,875 (2002 - 2,474,875) options with exercise prices between \$0.77 and \$4.55 were outstanding and exercisable at various dates to December 11, 2008. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

The following tables summarize the information about the share options as at December 31:

	2003		2002	
	Shares	Weighted average exercise price	Shares	Weighted average exercise price
<i>Fixed Options</i>				
Outstanding at beginning of year	2,474,875	\$1.36	1,397,500	\$0.77
Granted	1,268,875	\$3.80	1,200,875	\$1.99
Exercised	(125,000)	\$1.15	(110,500)	\$0.77
Cancelled	(212,875)	\$2.23	(13,000)	\$0.77
Outstanding at end of year	3,405,875	\$2.22	2,474,875	\$1.36
Options exercisable at year end	637,000	\$1.01	232,375	\$0.77

	Options outstanding			Options exercisable	
	Number outstanding at December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable at December 31, 2003	Weighted average exercise price
<i>Range of exercise prices</i>					
\$ 0.77 - \$ 1.50	1,192,750	7.9	\$ 0.77	497,250	\$ 0.77
\$ 1.85 - \$ 2.20	975,225	8.5	\$ 2.01	139,750	\$ 1.87
\$ 2.63 - \$ 3.95	564,275	9.1	\$ 3.27	—	\$ —
\$ 4.00 - \$ 4.55	673,625	8.8	\$ 4.22	—	\$ —
	3,405,875		\$ 2.22	637,000	\$ 1.01

For options granted to employees from January 1, 2002 to December 31, 2002, the Company follows the settlement method of accounting. Since all options were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the 2002 option grants. Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards, the Company's net earnings and net earnings per share for the year ended December 31, 2002 would have been the pro forma amounts indicated following:

	2003	2002
	\$	\$
Net earnings		
As reported	10,505	1,794
Pro forma	10,345	1,750
Net earnings per common share - basic		
As reported	0.30	0.08
Pro forma	0.30	0.08
Net earnings per common share - diluted		
As reported	0.29	0.07
Pro forma	0.28	0.07

For options granted after January 1, 2003, the Company follows the fair value method (note 3).

The weighted average fair market value of options granted in the year ended December 31, 2003 are \$1.39 per option. The fair market of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions:

	2003	2002
Risk-free interest rate	4.50%	4.00%
Estimated hold period prior to exercise (years)	5	4
Volatility in the price of the Company's common shares	38%	44%
Dividend per share	\$0.00	\$0.00

10. PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year.

In the calculation of diluted per share amounts, options under the stock option plan are assumed to have been converted or exercised on the later of the beginning of the year and the date granted. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market rate.

	2003	2002
Weighted average shares outstanding (thousands)		
Basic	34,865	23,024
Diluted	36,318	24,016

11. INCOME TAXES

The provision for income tax differs from the result which would be obtained by applying the combined Federal and Provincial statutory income tax rates to income before taxes. This difference results from the following:

	2003	2002
	\$	\$
Earnings (loss) before taxes	17,216	3,573
Statutory income tax rate	40.6%	42.8%
Expected income tax	6,990	1,529
Increase (decrease) resulting from:		
Non-deductible crown charges	2,769	760
Resource allowance	(3,044)	(597)
Statutory rate adjustment	(310)	(224)
Other	—	23
Change in valuation allowance	—	172
Provision for taxes	6,405	1,663

The future income tax liability is comprised of temporary differences related to the following:

	2003	2002
	\$	\$
Property and equipment	(9,572)	(928)
Statutory tax rate adjustment	339	286
Future site restoration	201	44
Share issue	759	313
Non-capital losses	946	827
Valuation allowance	(770)	(542)
Future income taxes	8,097	—

12. SUPPLEMENTAL

Changes in non-cash working capital:

**CASH FLOW
INFORMATION**

	2003	2002
	\$	\$
Accounts receivable	(7,264)	(3,187)
Prepaid expenses	(227)	509
Accounts payable	9,098	6,373
Changes in non-cash working capital	1,607	3,695
These changes relate to the following activities:		
Operating activities	3,717	(706)
Investing activities	(2,110)	4,401
	1,607	3,695

Amounts paid during the year relating to interest expense and capital taxes are as follows:

	2003	2002
	\$	\$
Interest paid in the year	1,204	220
Capital taxes paid in the year	210	—
	1,414	220

13. FINANCIAL INSTRUMENTS

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

a) Commodity Price Risk Management

Financial instruments are entered into by the Company to protect the downside prices received on the sale of a portion of its crude oil and natural gas production. The agreements entered into are forward transactions providing the Company with a range of fixed prices on the commodities sold. Petroleum and natural gas revenue for the year ended December 31, 2003 include losses of \$1.7 million (2002 - \$133 thousand loss) on those transactions.

The following contracts were outstanding as at December 31, 2003:

Commodity	Type	Term	Volume	Price	Index
Natural gas	Fixed	January 2004 - March 2004	6,000 GJ's/d	\$6.57/GJ	AECO
Crude oil	Fixed	January 2004 - March 2004	600 bbls/d	US \$28.70/bbl	WTI
Crude oil	Fixed	April 2004 - June 2004	600 bbls/d	US \$27.50/bbl	WTI
Crude oil	Fixed	July 2004 - September 2004	400 bbls/d	US \$28.25/bbl	WTI
Crude oil	Fixed	October 2004 - December 2004	300 bbls/d	US \$27.30/bbl	WTI

The estimated fair value at December 31, 2003 of these transactions, had the contracts been settled at that time, would be a loss of \$487 thousand.

b) Credit Risk Management

The Company has estimated that the fair value of its financial instruments, which include accounts receivable, accounts payable and accrued liabilities, and long-term debt, approximate their carrying values.

The majority of the Company's accounts receivable are with other companies in the oil and gas industry and are subject to normal industry credit risk.

14. SUBSEQUENT EVENTS

On January 22, 2004, the Company acquired crude oil and natural gas assets that produce approximately 580 barrels of oil equivalent per day of production for approximately \$23 million. The acquisition included working interests in existing Company operated producing properties, gas processing facilities, infrastructure and undeveloped land.

As a result of completion of the above mentioned acquisition, the Company renegotiated its credit facilities as described in note 6.

On February 2, 2004, the Company issued 4,250,000 common shares at a price of \$4.50 per share for gross proceeds of \$19.1 million.

SCHEDULE C



GREAT NORTHERN EXPLORATION LTD.

CONSOLIDATED BALANCE SHEET

	March 31, 2004	December 31, 2003
	<i>(unaudited)</i>	<i>(Restated – note 3)</i>
	\$	\$
ASSETS		
Current assets		
Accounts receivable	11,473,000	12,456,000
Prepaid expenses	546,000	609,000
	<u>12,019,000</u>	<u>13,065,000</u>
Property and equipment (note 4)	160,448,000	125,718,000
	<u>172,467,000</u>	<u>138,783,000</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	21,916,000	19,754,000
Bank debt (note 5)	45,596,000	38,555,000
	<u>67,512,000</u>	<u>58,309,000</u>
Future income taxes	9,641,000	8,097,000
Asset retirement obligations (note 8)	7,866,000	6,923,000
	<u>85,019,000</u>	<u>73,329,000</u>
Shareholders' equity		
Share capital (note 6)	72,859,000	54,281,000
Contributed surplus	251,000	136,000
Retained earnings	14,338,000	11,037,000
	<u>87,448,000</u>	<u>65,454,000</u>
Subsequent event (note 10)	172,467,000	138,783,000

(See accompanying notes to the consolidated financial statements)

GREAT NORTHERN EXPLORATION LTD.

CONSOLIDATED STATEMENT OF OPERATIONS AND RETAINED EARNINGS

<i>Three months ended March 31,</i>	2004	2003 (Restated – note 3) <i>(unaudited)</i>
	\$	\$
Revenue		
Petroleum and natural gas sales	19,529,000	8,895,000
Royalties, net	(3,909,000)	(2,019,000)
	<u>15,620,000</u>	<u>6,876,000</u>
Expenses		
Operating	3,892,000	1,367,000
General and administrative	304,000	324,000
Financial charges	538,000	51,000
Depletion, depreciation and accretion (note 8)	5,591,000	1,531,000
	<u>10,325,000</u>	<u>3,273,000</u>
Earnings before taxes	<u>5,295,000</u>	<u>3,603,000</u>
Capital taxes	94,000	29,000
Future income taxes	1,900,000	1,402,000
	<u>1,994,000</u>	<u>1,431,000</u>
Net earnings	<u>3,301,000</u>	<u>2,172,000</u>
Retained earnings, beginning of period	<u>12,103,000</u>	<u>1,598,000</u>
Retroactive application of change in accounting policy (note 3(b))	<u>(1,066,000)</u>	<u>(390,000)</u>
Retained earnings, end of period	<u>14,338,000</u>	<u>3,380,000</u>
Net earnings per share		
Basic	\$0.08	\$0.07
Diluted	\$0.08	\$0.07

(See accompanying notes to the consolidated financial statements)

GREAT NORTHERN EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CASH FLOW

<i>Three months ended March 31,</i>	2004	2003 (Restated – note 3)
	\$	\$ (unaudited)
Cash flow related to the following activities		
Operating		
Net earnings for the period	3,301,000	2,337,000
Items not affecting cash:		
Depletion, depreciation and accretion	5,591,000	1,366,000
Future income taxes	1,900,000	1,402,000
Stock-based compensation	115,000	-
Cash flow from operations	10,907,000	5,105,000
Changes in non-cash operating working capital items	520,000	1,584,000
	11,427,000	6,689,000
Financing		
Change in bank debt	7,041,000	3,971,000
Share issuance, net	18,222,000	32,000
	25,263,000	4,003,000
Cash available for investment activities	36,690,000	10,692,000
Investing		
Property and equipment additions	(39,290,000)	(8,974,000)
Site restoration expenditures	(88,000)	(41,000)
Changes in non-cash investing working capital items	2,688,000	(1,677,000)
	(36,690,000)	(10,692,000)
Change in cash	-	-
Cash, beginning of period	-	-
Cash, end of period	-	-

(See accompanying notes to the consolidated financial statements)

GREAT NORTHERN EXPLORATION LTD.

SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

THREE MONTHS ENDED MARCH 31, 2004

(unaudited)

(tabular amounts in thousands of dollars, unless otherwise stated)

1. NATURE OF OPERATIONS

The Company is engaged primarily in the exploration for and development and production of petroleum and natural gas in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

a) Basis of Presentation

The consolidated financial statements include the accounts of Great Northern Exploration Ltd. (the "Company") and its wholly-owned subsidiaries.

The interim consolidated financial statements and the notes thereto of the Company have been prepared following the same accounting policies and methods of computation as the audited consolidated financial statements of the Company as at December 31, 2003 except as disclosed in note 3. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2003.

3. CHANGE IN ACCOUNTING POLICY

a) Full Cost Accounting Guideline

In January 2004, the Company adopted Accounting Guideline 16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants ("CICA") which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil & Gas Industry".

The recoverability of a cost center is tested by comparing the carrying value of the cost center to the sum of the undiscounted cash flows expected from the cost center's use and eventual disposition. If the carrying value is unrecoverable the cost center is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a credit adjusted risk free rate.

Under Accounting Guideline 5, future net revenues for ceiling test purposes were based on proved reserves and were not discounted. Estimated future general and administrative costs and financing charges associated with future net revenues were deducted in arriving at the "ceiling".

There were no charges to net income, property, plant and equipment or any other reported amounts in the consolidated financial statements as a result of adopting this guideline.

b) Asset Retirement Obligation

In January 2004, the Company adopted CICA Handbook Section 3110, "Asset Retirement Obligations". This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

The Company recognizes the fair value of its asset retirement obligation ("ARO") in the period in which it is incurred and when a reasonable estimate of fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs.

Previously, the Company recognized a provision for site restoration and abandonment costs calculated on the unit-of-production method over the life of the petroleum and natural gas properties based on total estimated proved reserves and the estimated future liability.

This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes as follows:

Consolidated Balance Sheet as at December 31, 2003

	<u>As Reported</u>	<u>Change</u>	<u>As Restated</u>
	\$	\$	\$
Assets			
Property and equipment	120,491	5,227	125,718
Liabilities and shareholders' equity			
Future site restoration	630	(630)	-
Asset retirement obligations	-	6,923	6,923
Retained earnings	12,103	(1,066)	11,037

Consolidated Statement of Operations and Retained Earnings for the Three Months ended March 31, 2003

	<u>As Reported</u>	<u>Change</u>	<u>As Restated</u>
	\$	\$	\$
Depletion and depreciation	1,366	90	1,456
Accretion	-	75	75
Net earnings	2,337	(165)	2,172

There was no impact on the Company's cash flow as a result of adopting this new policy. See note 7 for additional information on the asset retirement obligation and the impact on the consolidated financial statements.

4. PROPERTY AND EQUIPMENT

	March 31, 2004		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	\$	\$	\$
Petroleum and natural gas properties	180,938	20,549	160,389
Office equipment	92	33	59
	181,030	20,582	160,448

	December 31, 2003		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	\$	\$	\$
Petroleum and natural gas properties	140,773	15,121	125,652
Office equipment	88	22	66
	140,861	15,143	125,718

The Company has capitalized, as part of petroleum and natural gas properties, indirect exploration overhead relating to property acquisition, exploration and development activities of \$115 thousand for the three months ended March 31, 2004 (year ended December 31, 2003 - \$553 thousand).

At March 31, 2004, undeveloped land costs of \$9.4 million (December 31, 2003 - \$9.4 million) have been excluded from the amount subject to depletion and depreciation.

5. CREDIT FACILITIES

	March 31, 2004	December 31, 2003
	\$	\$
Prime rate advances	5,596	8,555
Bankers' acceptances	40,000	30,000
	45,596	38,555

The Company has a demand revolving credit facility to a maximum of \$70 million. The credit facility bears interest at the lenders' prime rate or at the Bankers' Acceptance rate plus a stamping fee of 1.25%. The \$70 million borrowing base is subject to a semi-annual and annual review by the lender. The credit facility is secured by a first fixed and floating charge debenture in the amount of \$100 million covering all the Company's assets.

6. SHARE CAPITAL

a) Authorized

Unlimited number of common voting shares
 Unlimited number of preferred shares, issuable in series

b) Issued

	Number of Shares	Amount \$
Balance, December 31, 2002	30,483,682	22,866
Issued on private placement	4,000,000	13,800
Issued on private placement	3,750,000	15,000
Exercise of stock options	125,000	142
Flow-through shares issued	1,100,000	6,050
Tax benefit renounced to shareholders	-	(2,456)
Share issue costs, net of future tax	-	(1,121)
Balance, December 31, 2003	39,458,682	54,281
Issued on private placement	4,250,000	19,125
Exercise of stock options	6,250	12
Share issue costs, net of future tax	-	(559)
Balance, March 31, 2004	43,714,932	72,859

In December 2003, 1,100,000 flow-through common shares were issued at a price of \$5.50 per share for gross proceeds of \$6.1 million. Under the terms of the flow-through agreement, the Company is required to expend \$6.1 million on qualifying crude oil and natural gas expenditures prior to December 31, 2004.

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year.

The reconciling items between the basic and diluted average common shares outstanding are outstanding stock options.

	Three months ended March 31,	
	2004	2003
Weighted average shares outstanding (thousands)		
Basic	42,173	30,499
Diluted	43,876	31,637

7. STOCK-BASED COMPENSATION

The Company has implemented a Stock Option Plan for directors and employees. Options under the Plan vest over a four year period with 25% vesting upon each anniversary date of the grant. As of March 31, 2004, there were 2,995,000 common shares reserved for issuance to eligible participants. At March 31, 2004, 3,423,375 (December 31, 2003 - 3,405,875) options with exercise prices between \$0.77 and \$4.60 were outstanding and exercisable at various dates to December 11, 2008. On April 6, 2004, 435,375 conditionally granted share options with an exercise price of \$4.25 were cancelled. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

The following tables summarize the information about the share options:

	Three months ended March 31, 2004		Year ended December 31, 2003	
	Shares	Weighted average exercise price	Shares	Weighted average exercise price
Fixed Options				
Outstanding at beginning of period	3,405,875	\$2.22	2,474,875	\$1.36
Granted	93,750	\$4.33	1,268,875	\$3.80
Exercised	(6,250)	\$2.00	(125,000)	\$1.15
Cancelled	(70,000)	\$4.00	(212,875)	\$2.23
Outstanding at end of period	3,423,375	\$2.24	3,405,875	\$2.22
Options exercisable at period end	682,750	\$1.12	637,000	\$1.01

Range of exercise prices	Options outstanding			Options exercisable	
	Number outstanding at March 31, 2004	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable at March 31, 2004	Weighted average exercise price
\$0.77 - \$1.50	1,192,750	7.7	\$0.77	500,500	\$0.77
\$1.85 - \$2.20	968,975	8.3	\$2.01	133,500	\$1.86
\$2.63 - \$3.95	564,275	8.7	\$3.27	48,750	\$2.66
\$4.00 - \$4.60	697,375	8.6	\$4.26	-	\$ -
	3,423,375		\$2.24	682,750	\$1.12

For options granted to employees from January 1, 2002 to December 31, 2002, the Company follows the settlement method of accounting. Since all options were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the 2002 option grants. Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards, the Company's net earnings and net earnings per share for the year ended December 31, 2002 would have been the pro forma amounts indicated below:

	2004	2003 (Restated – note 3)
Net earnings		
As reported	\$3,301	\$2,172
Pro forma	\$3,260	\$2,146
Net earnings per common share – basic		
As reported	\$0.08	\$0.07
Pro forma	\$0.08	\$0.07
Net earnings per common share – diluted		
As reported	\$0.08	\$0.07
Pro forma	\$0.07	\$0.07

For options granted after January 1, 2003, the Company follows the fair value method.

The weighted average fair market value of options granted in the year ended March 31, 2004 is \$1.08 per option. The fair market of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions:

	2004	2003
Risk-free interest rate	4.50%	4.50%
Estimated hold period prior to exercise (years)	5	5
Volatility in the price of the Company's common shares	15%	38%
Dividend per share	\$0.00	\$0.00

8. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are based on the Company's net ownership in wells and facilities and management's estimate of costs to abandon and reclaim those wells and facilities as well as an estimate of the future timing of the costs to be incurred.

The Company has estimated the present value of its total asset retirement obligations to be \$7.9 million at March 31, 2004 based on a total future liability of \$21.1 million. Payments to settle asset retirement obligations occur over the operating lives of the underlying assets, estimated to be from zero to 50 years, with the majority of costs incurred between 2010 and 2026. Estimated cash flows have been discounted at the Company's credit-adjusted risk free rate of 8 percent and an inflation rate of 2.0 percent.

	Three months ended March 31,		Year ended December 31,
	2004	2003	2003
Asset retirement obligations, beginning of period	6,923	3,155	3,155
Liabilities incurred during period	879	699	3,626
Liabilities settled during period	(88)	(41)	(348)
Accretion	152	75	490
Asset retirement obligations, end of period	7,866	3,888	6,923

9. FINANCIAL INSTRUMENTS

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

a) Commodity Price Risk Management

Financial instruments are entered into by the Company to protect the downside prices received on the sale of a portion of its crude oil and natural gas production. The agreements entered into are forward transactions providing the Company with a range of fixed prices on the commodities sold. Petroleum and natural gas revenue for the three months ended March 31, 2004 include losses of \$0.2 million (2003 - \$1.3 million loss) on those transactions.

The following contracts were outstanding as at March 31, 2004:

Commodity	Type	Term	Volume	Price	Index
Natural gas	Fixed	April 2004 – September 2004	4,000 GJ's/d	\$5.88/GJ	AECO
Natural gas	Fixed	October 2004 – December 2004	1,333 GJ's/d	\$5.88/GJ	AECO
Crude oil	Fixed	April 2004 – June 2004	600 bbls/d	US \$27.50/bbl	WTI
Crude oil	Fixed	July 2004 – September 2004	600 bbls/d	US \$29.17/bbl	WTI
Crude oil	Fixed	October 2004 – December 2004	600 bbls/d	US \$28.70/bbl	WTI

The estimated fair value at March 31, 2004 of these transactions, had the contracts been settled at that time, would be a loss of \$1.5 million.

10. SUBSEQUENT EVENT

Recent APF Offer

On April 7, 2004, APF Energy Inc., APF Energy Trust (collectively, the "Offeror") and Great Northern announced that the Offeror had agreed to make an offer to acquire all of the outstanding common shares of Great Northern Exploration Ltd. and all common shares which may become outstanding on the exercise of the outstanding stock options, on the basis of, at the election of the holder, either:

- a) \$5.05 cash for each Common Share; provided that not more than \$55.2 million in cash shall be payable in the aggregate under the Offer, with the balance being paid in trust units ("APF Units") of APF Energy Trust at an exchange rate of 0.414614 Trust Units per Common Share (the "Cash Alternative");
- b) 0.414614 Trust Units for each GNEL Share (the "Trust Unit Alternative"); or

subject to the stated maximum, any combination thereof (the "Offer") as more particularly described and upon the terms and subject to the conditions set forth in the "Offering Circular" dated April 26, 2004.

The Offer is scheduled to expire on June 1, 2004.



July 7, 2004

NANCY M. PENNER
DIRECT DIAL: (403) 294-7011
EMAIL: npenner@parlee.com
OUR FILE #: 51823-42/nmp

Securities Commissions in all Provinces of Canada

Re: APF Energy Trust Revised Business Acquisition Report

We are today filing a revised Business Acquisition Report for APF Energy Trust. The Business Acquisition Report has been amended to provide in item 3 that the auditors for an acquired company, Great Northern Exploration Ltd., have not provided a formal consent for the inclusion in the Business Acquisition Report of their audit report on the annual consolidated financial statements of Great Northern.

Yours truly,

PARLEE McLAWS LLP

(Signed)
"NANCY M. PENNER"
NMP/maz

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Rapport de gestion

Le rapport de gestion doit être lu à la lumière des états financiers consolidés intermédiaires non vérifiés des trimestres terminés les 31 mars 2004 et 2003. Les informations financières ont été préparées selon les PCGR du Canada et sont présentées en dollars canadiens. Des informations supplémentaires liées à APF, notamment les exigences en matière d'informations à fournir en vertu de la norme canadienne 51-101 (la « NC 51-101 »), se trouvent dans la notice annuelle de 2003 d'APF (la « notice annuelle ») sur SEDAR (www.sedar.com) ou sur le site Web d'APF (www.apfenergy.com).

PRODUCTION

Les volumes de production se sont établis à 12 % de plus au premier trimestre de 2004 qu'à la période correspondante de 2003, ce qui témoigne des conséquences des acquisitions effectuées en 2003 et du succès remporté par le programme de forage. La baisse naturelle de la production du pétrole brut a été compensée par une augmentation de 31 % de la production de gaz naturel acquise pendant 2003, principalement par le truchement de l'acquisition de Nycan Energy Corp. (« Nycan ») et mise en valeur au moyen de programmes de forage fructueux à Countess et Enchant. La production du deuxième trimestre augmentera en raison de l'acquisition de Great Northern Exploration Ltd. (« Great Northern ») prévue pour le début de juin 2004. Au moment de l'annonce de l'acquisition, Great Northern produisait environ 5 600 bep/j.

	Trimestres terminés les 31 mars		Variation %
	2004	2003	
Pétrole brut (b/j)	6 104	6 345	(4)
Gaz naturel (kpi ³ /j)	37 729	28 745	31
LGN (b/j)	424	264	61
Total (bep/j)	12 816	11 400	12
Répartition de la production			
Pétrole et LGN	51 %	58 %	(12)
Gaz naturel	49 %	42 %	17

COMMERCIALISATION

Pendant le premier trimestre, la production d'APF était constituée à 51 % de pétrole brut et de LGN et à 49 % de gaz naturel. Le pétrole brut s'est vendu aux termes de contrats à tacite reconduction sur 30 jours alors qu'environ 25 % de la production de gaz naturel s'est vendue à des courtiers-fournisseurs aux termes de contrats à long terme, les 75 % restant ayant été vendus sur le marché au comptant.

PRIX

Au cours du premier trimestre de 2004, les réalisations du prix du pétrole brut ont diminué de 13 % par rapport à la période correspondante de 2003. Même si le prix de référence du West Texas Intermediate (« WTI ») a augmenté de 4 % par rapport au premier trimestre de 2003, le principal facteur à se répercuter sur les prix a été la diminution de 13 % de la valeur du dollar américain par rapport au dollar canadien pendant la même période. Les réalisations du gaz naturel au cours du trimestre ont diminué de 14 % par rapport à la période correspondante de 2003, le prix AECO régressant de 17 % par rapport à la période correspondante. Pour le reste de 2004, les contrats à terme NYMEX laissent entrevoir que le prix du pétrole brut dépassera les niveaux de 2003. APF prévoit que le prix du gaz en 2004 demeurera comparable aux niveaux de 2003, ou même les dépassera, alors que les préoccupations relatives à l'offre domineront le marché.

En date du 1^{er} janvier 2004, APF a séparé les coûts associés au transport et à la vente du pétrole brut, du gaz naturel et des LGN. Auparavant, elle suivait la pratique ayant cours dans le secteur, à savoir présenter les produits après déduction de ces coûts. Par conséquent, le 31 mars 2004, des états comparatifs ont été retraités après séparation de ces coûts, ce qui a donné lieu à une augmentation du prix brut par unité de production.

	Trimestres terminés les 31 mars		
	2004	2003	Variation %
Prix – après opérations de couverture (\$ CA)			
Pétrole brut (b)	35,06 \$	40,32 \$	(13)
Gaz naturel (kpi ³)	6,95	8,10	(14)
LGN (b)	33,80	38,41	(12)
Total	38,27 \$	43,76 \$	(13)
Prix de référence			
WTI (\$ US/b)	35,15 \$	33,86 \$	4
Gaz AECO (\$ CA/kpi ³)	6,60 \$	7,92 \$	(17)
Taux de change (\$ US/\$ CA)	1,318 \$	1,510 \$	(13)

INSTRUMENTS DÉRIVÉS

Le prix des marchandises est sensible aux fluctuations du marché. APF gère activement le risque lié au prix des marchandises au moyen de contrats de couverture qui mettent les produits à l'abri des fluctuations du prix des marchandises. Les opérations de couverture visent à stabiliser les niveaux de distribution en espèces au moyen de la fixation du prix des marchandises pour une partie du portefeuille de production. Le prix des marchandises est une des principales hypothèses utilisées pour dresser le budget annuel d'APF et estimer les distributions annuelles. APF a pour mandat d'assurer la protection d'une partie des distributions de l'année, lesquelles sont déterminées d'après les hypothèses relatives au prix des marchandises. APF recherche les occasions de vente à découvert d'une partie de sa production à des niveaux égaux ou supérieurs aux prix des marchandises utilisés dans le processus d'établissement du budget.

Bien que cette directive implique nécessairement une hausse du prix des marchandises, il ne faut pas oublier qu'il peut aussi baisser. À cet effet, lorsque le prix des marchandises est inférieur à celui utilisé pour établir le budget annuel, la direction, en se fondant sur son expérience, prend les mesures nécessaires pour atténuer l'incidence de la baisse du prix des marchandises. Au premier trimestre de 2004, les opérations de couverture ont réduit les produits qui auraient autrement été reçus de 1,0 M\$, ce qui a fait diminuer de 3,77 \$/b le prix obtenu pour le pétrole et fait augmenter le prix obtenu pour le gaz naturel de 0,31 \$/kpi³.

En date du 1^{er} janvier 2004, L'Institut Canadien des Comptables Agréés (l'« ICCA ») a publié la note d'orientation 13 concernant la comptabilité intitulée « Relations de couverture ». Conformément à ces nouvelles recommandations, il faut consigner les opérations de couverture et démontrer que les couvertures sont suffisamment efficaces pour appliquer la comptabilité de couverture. APF constatait auparavant seulement les gains et les pertes de couverture au fur et à mesure qu'ils se matérialisaient à la fin du contrat. Un examen des relations de couverture existantes a révélé que les couvertures visant les marchandises, les taux d'intérêt et le change d'APF ne sont pas admissibles à la comptabilité de couverture. Les gains et les pertes estimatifs sur les contrats ont été portés à l'état des résultats du trimestre se terminant le 31 mars 2004. Les couvertures de gaz naturel AECO d'APF sont effectivement admissibles; toutefois, la Fiducie a décidé de ne pas appliquer la comptabilité de couverture à ces instruments puisque la direction estime que, si elle appliquait la comptabilité de couverture à certaines opérations et non à d'autres, elle compromettrait la transparence de l'information financière et risquerait d'induire les lecteurs en erreur.

Au 1^{er} janvier 2004, APF a constaté une somme de 1,3 M\$ pour la valeur axée sur la valeur marchande des couvertures en vigueur comme s'il s'agissait d'un passif lié aux instruments dérivés et une perte reportée relative aux instruments dérivés de 1,3 M\$ devant se matérialiser au règlement des instruments dérivés correspondants. La perte reportée au 1^{er} janvier 2004 se composait d'une perte de 0,4 M\$ pour le pétrole brut et le gaz naturel et d'une perte de 0,9 M\$ pour des swaps de taux d'intérêt. Au 31 mars 2004, une tranche de 0,12 M\$ de la perte reportée a été constatée, le solde de 1,18 M\$ devant être constaté pendant le reste de 2004. Au 31 mars 2004, la juste valeur des instruments dérivés s'établissait à 4,44 M\$. Cette perte a été constatée comme un passif lié aux instruments dérivés, et une somme de 3,14 M\$ a été portée au poste des charges à l'état des résultats afin de tenir compte de la variation des justes valeurs depuis le 31 décembre 2003.

Au 31 mars 2004, APF disposait des couvertures suivantes :

Période	Marchandise	Type de contrat	Quantité quotidienne moyenne	Prix moyen de couverture
Avril à juin 2004	Pétrole brut	Swap	2 500 b	30,78 \$ US/b
Avril à juin 2004	Gaz naturel	Swap	10 333 GJ	5,76 \$ CA/GJ
Avril à juin 2004	Gaz naturel	Swap	1 000 Mbtu	5,19 \$ US/Mbtu
Juillet à septembre 2004	Pétrole brut	Swap	2 167 b	29,58 \$ US/b
Juillet à septembre 2004	Gaz naturel	Swap	10 000 GJ	5,75 \$ CA/GJ
Juillet à septembre 2004	Gaz naturel	Swap	1 000 Mbtu	5,19 \$ US/Mtu
Octobre à décembre 2004	Pétrole brut	Swap	1 833 b	30,45 \$ US/b
Octobre à décembre 2004	Gaz naturel	Swap	3 333 GJ	5,75 \$ CA/GJ
Octobre à décembre 2004	Gaz naturel	Swap	333 Mbtu	5,19 \$ US/Mbtu
Janvier 2005	Pétrole brut	Swap	1 000 b	31,74 \$ US/b

En plus des opérations de couverture du prix des marchandises, APF a aussi conclu des contrats de couverture de risque de change pour atténuer les risques liés au taux de change. La Fiducie a couvert 20 M\$ US de produits à un taux de 1,3317 \$ CA ou 0,7509 \$ US pour l'année civile 2004.

Au 31 décembre 2004, APF avait fixé le taux d'intérêt sur une partie de sa dette comme suit :

Durée	Montant (en milliers de dollars)	Taux d'intérêt
Avril 2004 à mars 2007	20 000 \$	3,58 %, majoré d'une commission d'acceptation
Avril 2004 à mai 2006	20 000 \$	3,60 %, majoré d'une commission d'acceptation
Avril 2004 à novembre 2005	20 000 \$	3,58 %, majoré d'une commission d'acceptation

PRODUITS

Pétrole et gaz (en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars			
	2004	Pourcentage du total	Retraité 2003	Pourcentage du total
Ventes de pétrole brut	21 569 \$	49	25 107	56
Ventes de gaz naturel	22 783	51	21 228	48
Ventes de LGN	1 305	3	914	2
Couverture du prix des marchandises	(1 027)	(2)	(2 345)	(5)
Transports	(865)	(1)	(811)	(1)
Autres	698	1	409	1
Total des produits	44 463 \$	100	44 502 \$	100
Par bep	38,12 \$		43,37 \$	

Les produits du premier trimestre de 2004, déduction faite de la couverture, ont été comparables à ceux du premier trimestre de 2003 en s'établissant à 44 M\$. La hausse des produits tirés du gaz naturel a compté pour 51 % du total des produits du premier trimestre de 2004, soit une augmentation de 1,6 M\$ par rapport à la période correspondante de l'exercice précédent. Les produits tirés de la vente du pétrole brut ont reculé de 3,5 M\$ depuis le premier trimestre de 2003 à la suite de la baisse de la production et des prix réalisés. En date du 1^{er} janvier 2004, APF a séparé les coûts associés au transport et à la vente du pétrole brut, du gaz naturel et des LGN. Auparavant, elle suivait la pratique ayant cours dans le secteur, à savoir présenter les produits après déduction de ces coûts. Par conséquent, les états comparatifs au 31 mars 2003 ont été retraités pour tenir compte de cette séparation.

REDEVANCES

Au premier trimestre, le total des redevances en pourcentage des produits demeurait au taux constant de 20,0 %. Les redevances par baril d'équivalent pétrole ont diminué de 12 % en 2004 par suite de l'évolution du portefeuille de propriétés et des redevances à payer.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation
	2004	2003	%
Redevances à la Couronne	5 426 \$	5 135 \$	6
Redevances de propriétaire franc	2 773	3 112	(11)
Redevances dérogatoires	858	845	2
Total des redevances	9 057 \$	9 092 \$	—
En pourcentage des produits, après opérations de couverture	20,0 %	20,1 %	—
Par bep	7,77 \$	8,86 \$	(12)

CHARGES D'EXPLOITATION

Au quatrième trimestre, les charges d'exploitation par bep se sont accrues de 17 % par rapport à la même période en 2003, passant de 6,55 \$ à 7,64 \$. Ces hausses sont surtout attribuables aux coûts d'optimisation des champs liés aux nouvelles propriétés d'APF ainsi qu'aux charges d'énergie plus élevées. Selon les prévisions, l'augmentation des charges d'énergie ainsi que l'accroissement des frais aux champs à l'égard du portefeuille actuel de propriétés d'APF devraient annuler tout gain d'efficacité de l'exploitation découlant des mesures prises pour comprimer les charges d'exploitation au deuxième et au troisième trimestres de 2004.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation
	2004	Retraité 2003	%
Charges d'exploitation	8 910 \$	6 719 \$	33
Par bep	7,64 \$	6,55 \$	17

REVENU NET

Le revenu net tiré de l'exploitation par bep a diminué de 19 % par rapport à la période correspondante de 2003 en raison, à la fois, d'une baisse des prix et d'une augmentation des charges d'exploitation, facteurs qui ont été partiellement compensés par une réduction des redevances par baril d'équivalent pétrole.

(\$/bep)	Trimestres terminés les 31 mars		Variation
	2004	2003	%
Produit net (après les opérations de couverture)	38,12 \$	43,37 \$	(11)
Redevances	(7,77)	(8,86)	(12)
Charges d'exploitation	(7,64)	(6,55)	17
Revenu net	22,71 \$	27,96 \$	(17)

FRAIS GÉNÉRAUX ET ADMINISTRATIFS

Les frais généraux et administratifs ont augmenté en chiffres absolus et par bep par rapport à la période correspondante de 2003. Cette hausse est imputable à l'accroissement des coûts liés à l'effectif, qui témoigne de l'accroissement de la taille de l'entreprise d'APF.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation %
	2004	2003	
Charges d'exploitation	1 839 \$	1 374 \$	34
Par bep	1,58 \$	1,34 \$	18

INTÉRÊTS

Les intérêts débiteurs ont diminué en chiffres absolus et par bep comparativement à la période correspondante de 2003 en raison de la baisse de la dette, qui est passée de 97 M\$ au trimestre terminé le 31 mars 2003 à 55 M\$ au trimestre correspondant de 2004.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation %
	2004	2003	
Intérêts débiteurs	977 \$	1 153 \$	(15)
Par bep	0,84 \$	1,12 \$	(25)

ÉPUISEMENT, AMORTISSEMENT ET DÉSACTUALISATION

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation %
	2004	Retraité 2003	
Épuisement, amortissement et désactualisation	17 033 \$	10 540 \$	62
Par bep	14,60 \$	10,16 \$	44

L'épuisement, amortissement et désactualisation a augmenté de 62 % par bep au premier trimestre de 2004 par rapport à la période correspondante de 2003. Cette augmentation par rapport à l'exercice précédent est attribuable à l'accroissement du chiffre inscrit au poste des immobilisations en raison de l'adoption de l'obligation liée à la mise hors service d'immobilisations et de l'acquisition d'entreprises en 2003. Le chiffre correspondant inscrit au 31 mars 2003 au poste de l'épuisement, amortissement et désactualisation a été retraité pour tenir compte de l'adoption de l'obligation liée à la mise hors service d'immobilisations.

OBLIGATIONS LIÉES À LA MISE HORS SERVICE D'IMMOBILISATIONS

Pendant le premier trimestre, APF a adopté le chapitre 3110 du Manuel de L'Institut Canadien des Comptables Agréés (l'« ICCA ») intitulé « Obligations liées à la mise hors service d'immobilisations ». Cette modification de convention comptable a été appliquée rétroactivement, et les périodes antérieures présentées à des fins de comparaison ont été retraitées. Auparavant, APF constatait une provision pour coûts futurs de restauration et d'abandon des lieux calculée selon la méthode de l'amortissement proportionnel à l'utilisation, sur la durée des propriétés pétrolières et gazières, compte tenu du total des réserves prouvées estimatives, et un passif futur estimatif.

La direction a estimé l'obligation totale future liée à la mise hors service d'immobilisations en fonction de la participation d'APF dans tous les puits et toutes les installations. Cette estimation tient compte des coûts nécessaires à l'abandon et à la restauration des puits et des installations ainsi que du calendrier estimatif de ces activités de restauration des lieux.

En raison de l'adoption de cette nouvelle norme, au 31 décembre 2003, l'obligation liée à la mise hors service des immobilisations a été portée à 21,80 M\$, les immobilisations après déduction de l'épuisement cumulé ont augmenté de 12,42 M\$ et le passif d'impôts futurs a reculé de 0,23 M\$. Les bénéfices non répartis à l'ouverture, au 1^{er} janvier 2004, ont augmenté de 1,26 M\$ en raison de l'effet cumulatif des charges de désactualisation et d'épuisement, déduction faite de la provision cumulative pour la restauration des lieux et impôts sur les bénéfices futurs, sur l'obligation liée à la mise hors service d'immobilisations constatée rétroactivement jusqu'en 1996, soit l'année d'établissement de la Fiducie.

L'obligation liée à la mise hors service d'immobilisations a augmenté de 44 % par rapport au 31 mars 2003. Cette augmentation est principalement attribuable à l'acquisition des entreprises de Hawk, Nycan et CanScot pendant l'exercice ainsi qu'à la désactualisation de l'obligation liée à la mise hors service d'immobilisations visant à tenir compte du passage du temps.

(en milliers de dollars)	Trimestres terminés les 31 mars		Variation %
	2004	Retraité 2003	
Obligations liées à la mise hors service d'immobilisations	22 187 \$	15 398 \$	44

CHARGE DE RÉMUNÉRATION

APF a adopté prospectivement le chapitre 3870 du Manuel de l'ICCA intitulé « Rémunérations et autres paiements à base d'actions ». Selon les dispositions provisoires qui y sont contenues, les entités qui les ont adoptées prospectivement au 31 décembre 2003 ne doivent que constater la charge de rémunération liée aux options attribuées en 2003 et doivent présenter les données *pro forma* sur les options accordées en 2002. Puisque APF octroie des droits seulement une fois par année, soit au deuxième trimestre, la charge de rémunération constatée pendant le premier trimestre de 2004 concerne uniquement des droits octroyés en 2003. La charge de rémunération au 31 mars 2003 a été retraitée puisque la norme a été adoptée pendant le quatrième trimestre de 2003.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars	
	2004	Retraité 2003
Charge de rémunération	257 \$	8 \$
Par bep	0,22 \$	0,01 \$

IMPÔTS

L'impôt sur le capital de la Saskatchewan et l'impôt fédéral des grandes sociétés ont diminué de 28 % pendant le trimestre, comparativement à 2003, en raison d'une réduction des taux de l'impôt sur le capital pendant la période correspondante.

Les impôts sur les bénéfices futurs sont inscrits dans la mesure où la valeur comptable des actifs acquis, excluant l'écart d'acquisition, excède leur valeur fiscale. Ces passifs d'impôts futurs font augmenter la valeur comptable des actifs acquis. Il est prévu que les passifs d'impôts futurs ne seront pas payés par APF Energy, mais seront plutôt transférés aux porteurs de parts au même titre que le revenu. En conséquence, les passifs d'impôts futurs diminueront chaque année et ils seront alors constatés à titre d'économie d'impôts à ce moment, dans la mesure où aucun impôt sur les bénéfices n'a été payé par APF Energy. Pendant le premier trimestre, l'économie d'impôts sur les bénéfices s'est chiffrée à 5,6 M\$, en regard de charges d'impôts futurs (retraité) de 1,09 M\$ en 2003, pour un solde de 58,6 M\$ des impôts sur les bénéfices futurs payables au 31 mars 2004. Les impôts sur les bénéfices futurs de 2003 ont été retraités pour tenir compte de l'adoption de l'obligation liée à la mise hors service d'immobilisations. Au 31 décembre 2003, ce retraitement a eu pour effet de diminuer de 0,23 M\$ les impôts sur les bénéfices futurs.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		
	2004	Retraité 2003	Variation %
Impôts sur le capital et autres impôts	605 \$	836 \$	(28)
Par bep	0,52 \$	0,81 \$	(36)
Charge (économie) d'impôts sur les bénéfices futurs	(5 607) \$	1 093 \$	613

BÉNÉFICE NET

Le bénéfice a diminué de 41 % pour s'établir à 8,1 M\$ ou 0,19 \$ par part de fiducie (bénéfice dilué par part de 0,19 \$) au 31 mars 2004, comparativement à 13,7 M\$ ou 0,54 \$ par part de fiducie (bénéfice dilué par part de 0,54 \$) au 31 mars 2003. Cette diminution est imputable à la réduction du revenu net tiré de l'exploitation, à l'obligation liée à la mise hors service d'immobilisations s'appliquant à l'épuisement, amortissement et désactualisation, et à la constatation d'une perte sur instruments dérivés au 31 mars 2004.

RÉSUMÉ DES RÉSULTATS TRIMESTRIELS

(en milliers de dollars, sauf les montants par part)	2004	2003 (retraité)				2002 (retraité)			
	T1 \$	T1 \$	T2 \$	T3 \$	T4 \$	T1 \$	T2 \$	T3 \$	T4 \$
Produits	46 355	47 658	41 876	39 970	39 110	16 941	21 495	26 204	29 380
Bénéfice net	8 127	13 687	21 195	11 552	(3 166)	2 444	4 459	5 493	(942)
Par part – de base (en dollars)	0,19	0,54	0,66	0,32	(0,09)	0,14	0,22	0,25	(0,04)
Par part – dilué (en dollars)	0,19	0,54	0,65	0,31	(0,09)	0,14	0,22	0,25	(0,04)

Les produits ont augmenté en proportion de la production qui est attribuable aux initiatives de mise en valeur et aux acquisitions d'entreprises en 2002 et en 2003. Le bénéfice a diminué en raison de l'augmentation de l'épuisement, amortissement et désactualisation, de l'effet sur l'obligation liée à la mise hors service d'immobilisations sur l'épuisement, amortissement et désactualisation et de la constatation des pertes de couverture pendant le premier trimestre de 2004. La perte constatée pendant le quatrième trimestre de 2003 est imputable aux conséquences du régime d'intéressement à court terme ainsi qu'à la réduction des prix des marchandises, lesquels se sont ressaisis au cours du premier trimestre de 2004.

DÉPENSES EN IMMOBILISATIONS, ACQUISITIONS ET CESSIIONS

Le montant net des dépenses en immobilisations s'est établi à 12,6 M\$ au premier trimestre, comparativement à 63,0 M\$ au premier trimestre de 2003. Au premier trimestre, APF a dépensé 11,8 M\$ du programme de dépenses en immobilisations budgété de 40,0 M\$, principalement dans le centre de l'Alberta et dans le sud-est de la Saskatchewan. Une fois l'acquisition de Great Northern terminée, APF s'attend à enregistrer une légère hausse de son programme de dépenses en immobilisations qui sera financé à la fois au moyen des flux de trésorerie, du produit tiré du réinvestissement des distributions et de la dette.

(en milliers de dollars)	Trimestres terminés les 31 mars	
	2004	2003
Acquisitions de sociétés	– \$	57 146 \$
Acquisition de propriétés	925	323
Acquisitions de terrains	1 432	315
Sismique	734	204
Forage et complétions de puits	7 560	3 961
Installations de production	1 829	1 004
Autres	280	83
Total partiel	12 760 \$	63 036 \$
Cessions	(199)	–
Dépenses en immobilisations, montant net	12 561 \$	63 036 \$

DISTRIBUTIONS EN ESPÈCES

Les distributions en espèces se sont élevées à 19,8 M\$, ou 0,525 \$ par part de fiducie, au premier trimestre de 2004, contre 13,1 M\$ ou 0,510 \$ par part de fiducie pour la période correspondante de 2003. Pendant le premier trimestre, APF a financé 1,5 M\$ des dépenses en immobilisations à partir de ses flux de trésorerie (5,57 M\$ en 2003), ce qui a produit un ratio de distribution de 92 % (51 % en 2003), compte tenu des intérêts cumulés sur les débentures convertibles. Pour le reste de 2004, APF a l'intention d'appliquer la même politique qu'elle a appliquée par le passé en matière de distributions, c'est-à-dire de conserver une partie des flux de trésorerie disponibles pour l'affecter au financement des dépenses en immobilisations et des projets de mise en valeur, son objectif étant de maintenir un ratio de 10 % à 20 %.

LIQUIDITÉS ET RESSOURCES EN CAPITAL

Au 31 mars 2004, APF avait une facilité de crédit à terme renouvelable de 150 M\$, sur laquelle 55 M\$ ont été prélevés (97 M\$ en 2003). Il est possible de faire des prélèvements sur la facilité de crédit ou de la rembourser en tout temps, et aucun calendrier de remboursement n'a été établi. Après l'achat de Great Northern, APF s'attend à ce que les modalités de la facilité soient modifiées pour tenir compte de la nouvelle base de réserves, puisque les prêteurs auront terminé leur revue annuelle, d'ici le 30 juin 2004.

Au 31 mars 2004, le solde des débentures convertibles, déduction faite des conversions, s'établissait à 46,3 M\$.

Au 31 mars 2004, APF accusait un déficit du fonds de roulement d'environ 6,1 M\$ contre un surplus de 10,2 M\$ au 31 décembre 2003. Le fonds de roulement déficitaire est principalement imputable à l'intensification des activités aux champs pendant l'hiver, période au cours de laquelle une partie importante des initiatives de forage et d'optimisation ont pris fin. Le produit tiré en février du financement par actions a servi à rembourser la dette et à combler partiellement le fonds de roulement déficitaire.

CAPITAUX PROPRES

Au 31 mars 2004, 39,7 millions de parts de fiducie d'APF étaient en circulation (27,0 millions en 2003), et sa capitalisation boursière s'établissait à environ 487 M\$ (278 M\$ en 2003).

Pendant le premier trimestre, APF a émis 744 692 parts de fiducie aux termes du régime de réinvestissement des distributions de primes pour un produit de 8,5 M\$ (néant en 2003).

Le 4 février 2004, APF a procédé à la clôture de l'émission de 4,77 millions de parts de fiducie à un prix de 11,60 \$ chacune pour un produit brut de 55,3 M\$. Le produit de ce placement a servi à financer le fonds de roulement et à rembourser la dette.

RISQUES COMMERCIAUX

APF est exposée à de nombreux risques inhérents au secteur du pétrole et du gaz. Ces risques pourraient avoir une incidence sur les distributions aux porteurs de parts. Pour réduire son exposition à ces risques, APF respecte des politiques et des procédures appropriées dans le cadre de ses activités quotidiennes et de sa planification stratégique à long terme.

Les risques financiers et les risques du marché liés aux fluctuations du prix des marchandises et des taux de change sont atténués au moyen de la gestion active par APF de la vente de sa propre production afin d'accroître au maximum les prix et au moyen d'un programme de couverture du prix des marchandises et des taux de change avec des contreparties solvables. APF a recours à des couvertures en tant qu'outils de gestion des risques et non pas à des fins de spéculation.

Des risques d'exploitation sont associés à la production de pétrole et de gaz naturel, en ce qui concerne la capacité de production, de traitement et de transport du pétrole et du gaz naturel, la capacité de remplacer la production et de conserver les réserves ainsi que les risques sur le plan de l'environnement et de la sécurité liés aux puits et aux installations de production. Pour atténuer ces risques, APF a recours à une stratégie d'exploitation pour une importante partie de sa production, ce qui lui procure un plus grand contrôle sur ses activités. APF engage des employés et des entrepreneurs qui respectent son programme de sécurité et qui s'informent régulièrement des pratiques en matière d'exploitation. En outre, APF conserve une assurance en vue de réduire les conséquences des pertes d'exploitation.

La croissance d'APF est fonction de sa capacité d'obtenir du financement par emprunt ou par actions sur les marchés financiers canadiens. APF dispose de marges de crédit auprès de trois banques à charte canadiennes. Celles-ci lui permettent de financer par emprunt ses acquisitions. Grâce à l'émission de nouveaux titres, APF est en mesure de rembourser sa dette tout en continuant de procéder à des acquisitions. Si APF n'avait plus accès aux marchés canadiens de la dette et des actions, elle pourrait avoir de la difficulté à remplacer sa production et à effectuer ses distributions.

Les changements apportés aux règlements gouvernementaux en matière de redevances, aux lois fiscales, aux programmes d'encouragement lié au secteur du pétrole et du gaz et aux lois sur les valeurs mobilières sont des exemples de modifications réglementaires qui peuvent influencer sur les activités d'APF.

Les changements apportés à de nombreuses variables ont une influence sur les flux de trésorerie d'APF. La sensibilité des flux de trésorerie avant couverture de 2004 s'établit comme suit :

Variable	Variation	Incidence sur les flux de trésorerie (en milliers de dollars)	Incidence par part
Prix du pétrole brut	1 \$ US par baril	2 360	0,07 \$
Prix du gaz naturel	0,10 \$ CA/kp ³	1 200	0,04 \$
Taux de change \$ US/\$ CA	0,01 \$	2 000	0,06 \$
Taux d'intérêt	1,00 %	1 000	0,03 \$
Production de pétrole brut	100 barils par jour	1 095	0,03 \$
Production de gaz naturel	1 Mp ³ par jour	1 500	0,04 \$

ESTIMATIONS COMPTABLES CRUCIALES

Pour dresser les états financiers conformément aux PCGR du Canada, APF doit faire des estimations et poser des hypothèses. Les questions décrites ci-après sont considérées comme cruciales pour comprendre les jugements posés pour préparer les états financiers ainsi que les incertitudes qui pourraient se répercuter sur les montants présentés au sujet des résultats d'exploitation, de la situation financière et des flux de trésorerie. Les conventions comptables sont décrites à la note 2 afférente aux états financiers vérifiés datés du 31 décembre 2003.

ESTIMATION DES RÉSERVES DE PÉTROLE ET DE GAZ

Les réserves de pétrole et de gaz ont été estimées conformément à la NC 51-101. De par leur nature, les estimations des réserves de pétrole et de gaz sont imprécises et ne représentent que des montants approximatifs. Elles sont de plus soumises à une révision future puisqu'elles sont déterminées d'après les données, les prix et les coûts disponibles sur les réservoirs au moment où ces estimations sont effectuées. En conséquence, les mesures financières établies en fonction des réserves estimatives peuvent aussi être modifiées.

ÉPUISEMENT ET AMORTISSEMENT

Les réserves prouvées sont utilisées dans les taux d'amortissement proportionnel au rendement pour calculer l'épuisement et l'amortissement des biens liés au pétrole et au gaz, notamment les immobilisations corporelles liées aux activités de production d'hydrocarbures. Le montant de l'amortissement est fonction des unités de production sur les réserves prouvées et mises en valeur du champ pertinent au cours de la période. Les propriétés non prouvées sont amorties selon les circonstances. Les autres immobilisations corporelles sont généralement amorties au moyen de la méthode de l'amortissement linéaire sur leur durée de vie utile de cinq à dix ans.

PLAFONNEMENT DU COÛT ENTIER

La valeur comptable des immobilisations est examinée pour déceler toute perte de valeur lorsque des faits ou des changements de circonstances laissent supposer que la valeur comptable de ces propriétés risque de ne pas être recouvrable. S'il est déterminé que les actifs ont subi une perte de valeur, leur valeur comptable est ramenée à la juste valeur. À cette fin, les actifs sont attribués à un centre de coûts selon le pays dans lequel l'activité s'est déroulée. Les estimations des flux de trésorerie futurs des actifs liés aux activités de production d'hydrocarbure sont déterminées d'après les réserves prouvées établies conformément à la NC 51-101.

FRAIS DE RESTAURATION ET D'ABANDON DES LIEUX

Des provisions sont constituées pour l'abandon et la restauration futurs des installations de production de pétrole et de gaz naturel et les pipelines à la fin de leur durée économique. Les frais de restauration et d'abandon des lieux sont déterminés d'après les exigences, la technologie et le niveau des prix actuels. La plupart de ces obligations s'étalent sur plusieurs années dans le futur et les exigences précises auxquelles nous devons satisfaire sont incertaines puisque les technologies et les coûts ainsi que les attentes sur les plans de la politique, de l'environnement et de la sécurité peuvent changer.

CHANGEMENTS RÉCENTS DE CONVENTIONS COMPTABLES OU DE RÈGLEMENTS

Obligations liées à la mise hors service d'immobilisations

L'Institut Canadien des Comptables Agréés (l'« ICCA ») a publié le chapitre 3110, « Obligations liées à la mise hors service d'immobilisations » en mars 2003. Conformément à cette nouvelle norme, les entités doivent constater l'obligation liée aux coûts futurs de restauration des lieux dans les états financiers. Cette nouvelle norme canadienne s'appliquera aux exercices débutant à compter du 1^{er} janvier 2004.

Conformément à cette norme, ces obligations sont d'abord mesurées à la juste valeur, puis ajustées pour tenir compte de la désactualisation et de la variation des flux de trésorerie sous-jacents. Le coût lié à la mise hors service d'immobilisations est capitalisé sur l'actif s'y rattachant et imputé aux résultats sur la durée de vie des actifs.

APF a adopté cette nouvelle norme au cours du premier trimestre et retraité rétroactivement les périodes antérieures, comme l'exigent les PCGR. Voir les notes 2 et 4 afférentes aux états financiers non vérifiés datés du 31 mars 2004 qui décrivent les conséquences de l'adoption de cette nouvelle norme.

Comptabilisation des instruments dérivés

En date du 1^{er} janvier 2004, APF a adopté la note d'orientation 13 de l'ICCA intitulée « Relations de couverture », qui traite de l'identification, de la désignation, de la consignation et de la mesure de l'efficacité des relations de couverture, aux fins de l'application de la comptabilité de couverture. Cette note s'applique aux exercices ouverts à compter du 1^{er} juillet 2003.

Cette nouvelle note aborde les opérations de couverture aux fins de l'application de la comptabilité de couverture en plus d'en établir les conditions d'application. Conformément à ces nouvelles recommandations, il faut consigner les opérations de couverture et démontrer que les couvertures sont suffisamment efficaces pour appliquer la comptabilité de couverture aux positions couvertes au moyen d'instruments dérivés. APF n'applique pas la comptabilité de couverture à ses relations d'instruments dérivés. Voir les notes 2 et 5 afférentes aux états financiers non vérifiés datés du 31 mars 2004 qui décrivent les conséquences de l'adoption de cette nouvelle norme.

Obligations d'information continue

Dès le 31 mars 2004, tous les émetteurs assujettis au Canada seront assujettis à de nouvelles exigences en matière d'obligations d'information continue conformément à la norme canadienne 51-102, « Obligations d'information continue ». Cette nouvelle norme s'applique aux exercices débutant à compter du 1^{er} janvier 2004. Cette norme propose des périodes de déclaration plus courtes pour le dépôt des états financiers annuels ou intermédiaires, des rapports de gestion et des notices annuelles.

Cette norme propose également de présenter davantage d'informations dans les états financiers et les rapports de gestion annuels ou intermédiaires et dans les notices annuelles. Selon cette nouvelle norme, il ne sera dorénavant plus obligatoire pour APF de poster les états financiers et rapports de gestion annuels ou intermédiaires aux porteurs de parts. Cependant, ces documents seront fournis sur demande.

Entités à détenteurs de droits variables

En juin 2003, l'ICCA a publié la note d'orientation comptable n° 15, « Consolidation des entités à détenteurs de droits variables », qui traite de la consolidation de certaines entités sur lesquelles le contrôle s'exerce autrement que par l'exercice des droits de vote. Cette note s'applique aux périodes annuelles et intermédiaires débutant à compter du 1^{er} novembre 2004. APF évalue actuellement l'incidence de ces nouvelles recommandations.

Comptabilisation des débetures convertibles

En juin 2003, l'ICCA a approuvé la modification du chapitre 3860 du Manuel intitulé « Instruments financiers – informations à fournir et présentation ». Conformément aux recommandations précédentes, les créances qui pouvaient être réglées au moyen des instruments de capitaux propres de l'entité pouvaient être classées à titre de capitaux propres, et les intérêts connexes étaient traités comme une réduction des capitaux propres.

Cette modification exige que certaines créances devant ou pouvant être réglées à l'aide des instruments de capitaux propres de l'entité soient présentées à titre de passif, les intérêts correspondants étant inscrits à l'état des résultats. Elle s'applique aux exercices débutant après le 1^{er} novembre 2004.

PERSPECTIVES

APF demeure engagée envers sa stratégie qui consiste à acheter des puits et à exploiter son patrimoine de propriétés au moyen de forages de développement, de remises en production et d'optimisations de champs. Pour 2004, elle a prévu forer 167 puits bruts au total. APF a attribué 40 M\$ au budget de ses dépenses en immobilisations pour l'exercice (compte non tenu des zones d'intérêt situées dans les terrains de Great Northern), 85 % des fonds étant consacrés au forage et à la mise en valeur de propriétés classiques. Au cours de 2004, APF poursuivra l'expansion de ses projets pilotes de gaz de gisements houillers dans le centre de l'Alberta. Au total, 7 M\$ ont été prévus au budget des dépenses en immobilisations pour les initiatives de gaz de gisements houillers au Canada et aux États-Unis. Avec une faible baisse de la production et la possibilité de générer des rendements plus élevés que ceux de la production classique, APF est d'avis que le gaz de gisements houillers représente une occasion très intéressante et idéale pour la structure de la Fiducie.

APF continuera de procéder à des acquisitions qui contribueront à améliorer, par part, les flux de trésorerie, la production, les réserves et la valeur liquidative d'APF. Cette dernière s'est engagée à préserver la stabilité à long terme des distributions en espèces. Pour atténuer les risques liés aux fluctuations du prix des marchandises qui sont inhérents au secteur du pétrole et du gaz naturel, APF couvrira activement sa production. À long terme, APF estime que les prix du pétrole brut et du gaz naturel se maintiendront à un niveau élevé.

Énoncés prospectifs

Certains énoncés contenus dans le présent document sont des « énoncés prospectifs », notamment les perspectives sur les prix du pétrole et du gaz, les redevances, les charges d'exploitation, les estimations de la production future, les dates d'achèvement estimatives des projets de construction et de mise en valeur, les plans d'affaires pour le forage et l'exploration, les montants estimatifs des dépenses en immobilisations et le moment où elles seront effectuées ainsi que les niveaux d'endettement futurs prévus. Les informations sur les réserves contenues dans ce document peuvent aussi être considérées comme des énoncés prospectifs puisque ces estimations comportent l'idée qu'il est possible de produire les ressources décrites de manière rentable. Les projections, les estimations et les opinions présentées dans ces énoncés prospectifs comportent forcément des risques et des incertitudes qui pourraient faire en sorte que les résultats financiers futurs réels diffèrent sensiblement des projections d'APF Energy Trust et d'APF Energy Inc. Ces risques incluent notamment : les risques liés au secteur du pétrole et du gaz (comme les risques d'exploitation liés à l'exploration; la mise en valeur et la production de pétrole brut et de gaz naturel; les risques et les incertitudes comportant la géologie des gisements de pétrole et de gaz; l'incertitude des estimations reliées aux réserves; l'incertitude des estimations et des projections concernant la production, les coûts et les charges; les délais possibles ou les changements de plans à l'égard des projets d'exploration ou de mise en valeur ou des dépenses en immobilisations et les risques liés à la santé, à la sécurité et à l'environnement); les risques liés à l'exécution des activités exercées à l'étranger (comme l'instabilité politique et budgétaire dans les pays où APF Energy fait des affaires); la possibilité que les politiques gouvernementales changent ou que les approbations des gouvernements soient retardées ou retenues et les fluctuations des prix et du taux de change. Ces risques et d'autres sont décrits dans les rapports d'APF Energy qui sont déposés auprès des organismes de réglementation des valeurs mobilières. Il n'est pas possible de déterminer avec certitude l'incidence d'un seul facteur sur un énoncé prospectif en particulier puisque ces facteurs sont dépendants d'autres facteurs et que la mesure qu'adoptera la direction dépendra de son évaluation de l'avenir compte tenu de toutes les informations dont elle dispose alors. Les lecteurs sont prévenus que la liste ci-dessus des facteurs importants n'est pas exhaustive. Bien que la société estime que les attentes contenues dans les énoncés prospectifs sont raisonnables d'après les informations disponibles au moment où elle les a formulées, aucune assurance ne peut être donnée quant aux résultats, aux niveaux d'activités et aux réalisations futurs. Tous les énoncés prospectifs subséquents, qu'ils soient présentés par écrit ou oralement, attribuables à APF ou à toute personne agissant en son nom sont expressément présentés sous réserve de cette mise en garde. APF n'a pas l'obligation de mettre à jour les énoncés prospectifs contenus aux présentes advenant un changement de circonstances, d'estimations ou d'opinions de la direction.

Bilans consolidés (non vérifié)

	31 mars 2004	31 décembre 2003
	(en milliers de dollars)	Retraité (note 2) (en milliers de dollars)
ACTIF		
Actif à court terme		
Encaisse	739	1 381
Comptes débiteurs	28 498	27 542
Perte sur instruments dérivés (note 5)	1 178	–
Autres éléments d'actif à court terme	3 703	3 506
	34 118	32 429
Fonds de mise hors service d'immobilisations	2 693	2 342
Écart d'acquisition	48 230	48 230
Immobilisations	409 923	413 706
	494 964	496 707
PASSIF		
Passif à court terme		
Comptes créditeurs et charges à payer	28 785	36 711
Passif lié aux instruments dérivés (note 5)	4 443	–
Distributions en espèces à payer	6 943	5 963
	40 171	42 674
Impôts sur les bénéfices futurs	58 614	63 991
Dette à long terme	55 000	98 000
Obligation liée à la mise hors service d'immobilisations (note 4)	22 187	21 803
	175 972	226 468
CAPITAUX PROPRES		
Compte de placement des porteurs de parts (note 6)	386 003	324 317
Surplus d'apport	1 325	1 241
Bénéfices non répartis	88 022	79 895
Distributions en espèces cumulées (note 3)	(199 192)	(179 363)
Déventures convertibles	46 277	46 466
Intérêts courus sur les déventures convertibles	(3 443)	(2 317)
	318 992	270 239
	494 964	496 707

États consolidés des résultats et des bénéfices non répartis (non vérifié)

Trimestres terminés les 31 mars	2004	2003
	(en milliers de dollars)	Retraité (note 2) (en milliers de dollars)
Produits		
Pétrole et gaz	46 355	47 658
Perte matérialisée sur instruments dérivés – montant net	(1 027)	(2 345)
Perte sur instruments dérivés autres qu'en espèces – montant net	(3 265)	–
Redevances, déduction faite du CIAR	(9 057)	(9 092)
Transports	(865)	(811)
	32 141	35 410
Charges		
Exploitation	8 910	6 719
Frais généraux et administratifs	1 839	1 374
Intérêts sur la dette à long terme	977	1 153
Épuisement, amortissement et désactualisation	17 033	10 540
Charge de rémunération à base d'actions	257	8
Impôts sur le capital et autres impôts	605	836
	29 621	20 630
Bénéfice avant impôts sur les bénéfices	2 520	14 780
Charge (économie) d'impôts sur les bénéfices futurs	(5 607)	1 093
Bénéfice net	8 127	13 687
Bénéfices non répartis au début de la période, déjà établi	78 637	35 589
Application rétroactive d'une modification de conventions comptables (note 2)	1 258	–
Bénéfices non répartis à la fin de la période, déjà établi	88 022	49 276
Bénéfice net par part – de base et dilué	0,19 \$	0,54 \$

États consolidés des flux de trésorerie (non vérifié)

Trimestres terminés les 31 mars	2004	2003
	(en milliers de dollars)	Retraité (note 2) (en milliers de dollars)
FLUX DE TRÉSORERIE LIÉS AUX ACTIVITÉS SUIVANTES :		
Activités d'exploitation		
Bénéfice net de la période	8 127	13 687
Éléments hors trésorerie		
Épuisement, amortissement et désactualisation	17 033	10 540
Impôts sur les bénéfices futurs	(5 607)	1 093
Charge de rémunération à base d'actions	257	8
Perte sur instruments dérivés autres qu'en espèces	3 265	–
Dépenses liées à la mise hors service d'immobilisations (note 4)	(75)	(134)
	23 000	25 194
Variation nette des éléments hors caisse du fonds de roulement		
Comptes débiteurs	(956)	(553)
Autres éléments d'actif à court terme	(197)	242
Comptes créditeurs et charges à payer	(3 423)	1 699
Montant à payer à APF Management	–	(3 923)
	(4 576)	(2 535)
Cotisations au fonds de mise hors service des immobilisations	(351)	(349)
	(18 073)	22 310
Activités d'investissement		
Acquisition de Hawk Oil	–	(3 457)
Nouvelles immobilisations	(11 834)	(5 567)
Achat de propriétés pétrolières et gazéifères	(925)	(324)
Produit de la cession de propriétés	199	–
Variation des éléments hors caisse du fonds de roulement – investissement	(2 966)	(1 556)
	(15 526)	(10 904)
Activités de financement		
Émission de parts contre espèces	55 387	28
Émission de parts dans le cadre du régime de réinvestissement des distributions	8 495	–
Émission de parts contre espèces à l'exercice d'options sur actions	509	414
Intérêts sur débentures convertibles	(1 126)	–
Frais d'émission des parts	(3 066)	(220)
(Remboursement)produit de l'émission de titres d'emprunt à long terme, montant net	(43 000)	1 100
Distributions en espèces	(19 829)	(13 066)
Variation des éléments hors caisse du fonds de roulement – financement	(559)	1 427
	(3 189)	(10 317)
Variation de l'encaisse au cours de la période	(642)	1 089
Encaisse au début de la période	1 381	950
Encaisse à la fin de la période	739	2 039

Renseignements supplémentaires (note 7)

NOTES AFFÉRENTES AUX ÉTATS FINANCIERS CONSOLIDÉS

31 mars 2004 et 2003 (non vérifié)

NOTE 1. PRINCIPALES CONVENTIONS COMPTABLES

Les états financiers consolidés intermédiaires d'APF Energy Trust (« APF ») ont été dressés par la direction conformément aux principes comptables généralement reconnus du Canada. Ils ont été préparés suivant les mêmes conventions comptables et méthodes de calcul que celles qui ont servi à préparer les états financiers consolidés de l'exercice terminé le 31 décembre 2003. Les états financiers consolidés intermédiaires doivent être lus en tenant compte des états financiers consolidés et des notes y afférentes présentés dans le rapport annuel d'APF pour l'exercice terminé le 31 décembre 2003.

NOTE 2. MODIFICATION DE CONVENTION COMPTABLE

Obligations liées à la mise hors service d'immobilisations

Veuillez vous reporter à la note 4 qui présente des renseignements supplémentaires au sujet de cette obligation.

Pendant le premier trimestre de 2004, APF a adopté le chapitre 3110 du Manuel de L'Institut Canadien des Comptables Agréés (l'« ICCA ») intitulé « Obligations liées à la mise hors service d'immobilisations ». Cette modification de convention comptable a été appliquée rétroactivement, et les périodes antérieures présentées à des fins de comparaison ont été retraitées.

Cette nouvelle norme exige la constatation de l'obligation liée aux coûts futurs de restauration des lieux des immobilisations corporelles à long terme dans les états financiers. Ce passif comprendrait la participation nette d'APF dans les puits productifs et dans les installations de traitement. Le passif lié aux obligations futures liée à la mise hors service d'immobilisations est porté aux états financiers au moment où il est engagé.

L'obligation liée à la mise hors service d'immobilisations est constatée initialement à la juste valeur estimative comme le passif à long terme, une augmentation correspondante étant portée au poste des immobilisations. L'amortissement des immobilisations est imputé aux charges selon la méthode de l'amortissement proportionnel au rendement. Le passif est accru à chaque période de présentation de l'information financière pour tenir compte de la juste valeur de tous les coûts futurs de restauration des lieux et de la désactualisation correspondante de la provision initiale. La désactualisation est imputée aux bénéfices de la période au cours de laquelle elle est engagée. La provision sera aussi révisée pour tenir compte des modifications du calendrier relatif aux flux de trésorerie ou aux coûts de restauration des lieux non actualisés. Les dépenses effectivement engagées pour la restauration des lieux sont imputées à l'obligation liée à la mise hors service d'immobilisations dans la mesure où le passif est inscrit au bilan. Les différences entre les coûts effectivement engagés et la juste valeur du passif constaté sont imputées aux bénéfices de la période en question.

Auparavant, APF constatait une provision pour coûts futurs de restauration et d'abandon des lieux calculée selon la méthode de l'amortissement proportionnel à l'utilisation, sur la durée des propriétés pétrolières et gazières, compte tenu du total des réserves prouvées estimatives, et un passif futur estimatif.

En raison de l'adoption de la nouvelle norme, au 31 décembre 2003, l'obligation liée à la mise hors service des immobilisations a été portée à 21,80 M\$, les immobilisations après déduction de l'épuisement cumulé ont augmenté de 12,42 M\$ et le passif d'impôts futurs a reculé de 0,23 M\$. Les bénéfices non répartis à l'ouverture, au 1^{er} janvier 2004, ont augmenté de 1,26 M\$ en raison de l'effet cumulatif des charges de désactualisation et d'épuisement, déduction faite de la provision cumulative pour restauration des lieux et impôts sur les bénéfices futurs, sur l'obligation liée à la mise hors service d'immobilisations constatées rétroactivement jusqu'en 1996, soit l'année d'établissement de la Fiducie.

Les états comparatifs des résultats et des bénéfices non répartis ont aussi été retraités au 31 mars 2003. L'épuisement, amortissement et désactualisation a diminué de 0,13 M\$, et la charge d'impôts futurs a augmenté de 0,06 M\$.

Comptabilisation des instruments dérivés

En date du 1^{er} janvier 2004, APF a adopté la note d'orientation 13 de l'ICCA, intitulée « Relations de couverture ». Cette note d'orientation traite de l'identification, de la désignation, de la consignation et de la mesure de l'efficacité des relations de couverture, aux fins de l'application de la comptabilité de couverture. Cette note s'applique aux exercices ouverts à compter du 1^{er} juillet 2003.

Cette nouvelle note aborde les opérations de couverture aux fins de l'application de la comptabilité de couverture en plus d'en établir les conditions d'application. Conformément à ces nouvelles recommandations, il faut consigner les opérations de couverture et démontrer que les couvertures sont suffisamment efficaces pour appliquer la comptabilité de couverture aux positions couvertes au moyen d'instruments dérivés. APF n'applique pas la comptabilité de couverture à ses relations de couverture.

Au 1^{er} janvier 2004, APF a constaté une somme de 1,3 M\$ pour la valeur axée sur la valeur marchande des couvertures en vigueur comme s'il s'agissait d'un passif lié aux instruments dérivés et une perte reportée relative aux instruments dérivés de 1,3 M\$ devant se matérialiser au règlement des instruments dérivés correspondants. La perte reportée au 1^{er} janvier 2004 se composait d'une perte de 0,4 M\$ pour le pétrole brut et le gaz naturel et d'une perte de 0,9 M\$ pour des swaps de taux d'intérêt.

Cette note d'orientation exige que tous les instruments dérivés soient mesurés à la juste valeur et portés au bilan comme un actif ou un passif. La NOC-13 exige aussi que toutes les variations de la juste valeur soient imputées aux bénéfices de la période, peu importe si le contrat a été réglé ou non. Tous les contrats sur instruments dérivés conclus par APF après le 1^{er} janvier 2004 ont été constatés soit comme un actif ou un passif sur instruments dérivés au bilan, un gain ou une perte non matérialisé correspondant étant inscrit à l'état des résultats.

Veuillez vous reporter à la note 5 qui présente des renseignements supplémentaires au sujet de ces instruments dérivés.

NOTE 3. ÉTAT DES DISTRIBUTIONS DE L'ENCAISSE

	Trimestres terminés les	
	31 mars	
	2004	2003
(en milliers de dollars, sauf les montants par part)		Retraité (note 2)
Ventes de pétrole et de gaz	45 328 \$	45 313 \$
Transports	(865)	(811)
Montant brut des redevances dérogatoires et des redevances des locateurs	(3 631)	(3 957)
	40 832	40 545
Moins :		
Charges d'exploitation	8 910	6 719
Frais généraux et administratifs	1 730	1 023
Frais de service de la dette	977	1 153
Apport au fonds d'abandon	426	483
Impôts sur le capital et autres impôts	605	836
Fonds de roulement financé par les flux de trésorerie	1 482	11 645
	14 130	21 859
Bénéfice assujéti à la redevance	26 702	18 686
99 % du bénéfice assujéti à la redevance	26 434	18 500
Droits à la Couronne, déduction faite du crédit d'impôt de l'Alberta au titre des redevances	(5 371)	(5 083)
Intérêts sur les débentures convertibles	(1 126)	–
Frais généraux et administratifs de la Fiducie	(108)	(351)
Espèces distribuées et disponibles pour distribution	19 829	13 066
Espèces distribuées à ce jour	12 886	8 074
Distributions en espèces à payer	6 943 \$	4 992 \$
Distributions en espèces déclarées par part, montant réel	0,525 \$	0,510 \$
Distributions en espèces cumulées au début de la période	179 363 \$	110 650 \$
Distributions déclarées et payées	12 886	8 074
Distributions déclarées et à payer	6 943	4 992
Distributions en espèces cumulées à la fin de la période	199 192 \$	123 716 \$

NOTE 4. OBLIGATIONS LIÉES À LA MISE HORS SERVICE D'IMMOBILISATIONS

La direction a estimé l'obligation totale future liée à la mise hors service d'immobilisations en fonction de la participation d'APF dans tous les puits et toutes les installations. Cette estimation tient compte des coûts nécessaires à l'abandon et à la restauration des puits et des installations ainsi que du calendrier estimatif de ces activités de restauration des lieux.

(en milliers de dollars)	
Obligation liée à la mise hors service d'immobilisations	
au 31 décembre 2003	21 803 \$
Dettes contractées	77
Dettes réglées	(75)
Charge de désactualisation	382
Obligation liée à la mise hors service d'immobilisations	
au 31 mars 2004	22 187 \$

Le montant non actualisé des flux de trésorerie estimatifs nécessaires au règlement de l'obligation s'établit à 72,6 M\$ (59,1 M\$ au 31 mars 2003). Les flux de trésorerie estimatifs ont été actualisés au moyen des taux sans risque et ajusté en fonction du crédit de 8,0 % et d'un taux d'inflation de 1,5 %. La durée prévue jusqu'au règlement varie d'un minimum de 5 ans jusqu'à un maximum de 50 ans, et les coûts seront payés au moyen des fonds réservés pour la restauration et l'abandon des lieux. Les réserves d'encaisse sont maintenant capitalisées à raison de 0,425 M\$ par trimestre au moyen des ressources d'exploitation d'APF.

NOTE 5. INSTRUMENTS DÉRIVÉS

Passif lié aux instruments dérivés (en milliers de dollars)	
Actif (passif) lié aux instruments dérivés au 31 décembre 2003	—
Pétrole brut	(1 395)
Gaz naturel	995
Change	—
Taux d'intérêt	(900)
Passif lié aux instruments dérivés au 1^{er} janvier 2004	(1 300)
Instruments dérivés réglés	1 416
Perte non matérialisée à la valeur du marché	(4 559)
Passif lié aux instruments dérivés au 31 mars 2004	(4 443)
Perte (gain) reportée sur instruments dérivés au 31 décembre 2003	
Pétrole brut	1 395
Gaz naturel	(995)
Change	—
Taux d'intérêt	900
Perte reportée sur instruments dérivés au 1^{er} janvier 2004	(1 300)
Instruments dérivés réglés	(122)
Perte reportée sur instruments dérivés au 31 mars 2004	1 178

NOTE 6. CAPITAUX PROPRES

	31 mars 2004		31 décembre 2003	
	Parts	(en milliers de dollars)	Parts	(en milliers de dollars)
Parts de fiducie				
Solde au début de la période	34 074 240	324 317	22 942 417	214 405
Émises pour l'acquisition de Hawk Oil	—	—	3 990 461	37 710
Émises pour l'acquisition de CanScot Resources	—	—	1 342 004	15 433
Émises contre espèces	4 774 698	55 387	5 351 645	55 670
Frais d'émission des parts	—	(3 066)	—	(3 467)
Régime de réinvestissement des distributions	744 692	8 495	140 710	1 602
Émises à la conversion de débentures	16 799	189	107 998	1 215
Émises à l'exercice d'options ou de droits	59 585	681	199 005	1 749
	39 670 014	386 003	34 074 240	324 317

Les données par part pour le trimestre terminé le 31 mars 2004 ont été établies en fonction d'un nombre moyen pondéré de parts de fiducie en circulation de 37 380 600 (25 161 387 au 31 mars 2003). Pour le calcul du bénéfice net dilué par part, 4 786 255 parts ont été ajoutées au nombre moyen pondéré de parts en circulation au cours du trimestre terminé le 31 mars 2004 (51 821 au 31 mars 2003) pour tenir compte de l'effet dilutif des options et des droits des salariés et des débentures convertibles.

Au cours du trimestre terminé le 31 mars 2004, aucune option sur des parts de fiducie n'a été attribuée à des salariés. Le régime d'options s'établissait comme suit au 31 mars 2004 et au 31 décembre 2003 :

	31 mars 2004		31 décembre 2003	
	Nombre d'options	Prix d'exercice moyen pondéré (en dollars)	Nombre d'options	Prix d'exercice moyen pondéré (en dollars)
Options sur parts de fiducie				
Solde au début de la période	126 469	9,59	244 029	9,13
Attribuées	—	—	—	—
Exercées	(12 993)	9,70	(106 786)	8,55
Annulées	—	—	(10 774)	9,42
En cours à la fin de la période	113 476	9,58	126 469	9,59
Options pouvant être exercées à la fin de la période	113 476	9,58	60 173	9,48

Au cours du trimestre terminé le 31 mars 2004, aucun droit d'achat de parts de fiducie n'a été attribué à des salariés ou à des administrateurs. Le régime de droits s'établissait comme suit au 31 mars 2004 et au 31 décembre 2003 :

	31 mars 2004		31 décembre 2003	
	Nombre de droits	Prix d'exercice moyen pondéré (en dollars)	Nombre de droits	Prix d'exercice moyen pondéré (en dollars)
Droits d'achat de parts de fiducie				
Solde au début de la période	1 824 330	9,09	429 333	9,37
Attribués	—	—	1 538 250	9,78
Exercés	(46 652)	(8,22)	(92 219)	9,05
Annulés	(117 815)	(9,63)	(51 034)	9,67
En cours avant la diminution de prix	1 659 863	9,75	1 824 330	9,72
Diminution du prix d'exercice	—	(0,82)	—	(0,63)
En cours à la fin de la période	1 659 863	8,93	1 824 330	9,09
Droits pouvant être exercés à la fin de la période	197 693	8,20	47 221	8,58

APF a constaté une charge de rémunération de 0,26 M\$ pour tenir compte des droits octroyés en 2003. En ce qui concerne les droits octroyés en 2002, APF a choisi de présenter les résultats pro forma comme si le chapitre 3870 du Manuel de l'ICCA intitulé « Rémunérations et autres paiements à base d'actions » avait été appliqué rétroactivement. Au 31 mars 2004, le bénéfice net pro forma et le bénéfice par action ne diffèreraient pas sensiblement des chiffres correspondants présentés dans les états consolidés des résultats et des bénéfices non répartis aux 31 mars 2004 et 2003.

NOTE 7. RENSEIGNEMENTS SUPPLÉMENTAIRES SUR LES FLUX DE TRÉSORERIE

	Trimestres terminés les 31 mars	
(en milliers de dollars)	2004	2003
Paiements en espèces liés aux éléments suivants :		
Intérêts	665	915
Intérêts sur les débetures	2 664	—
Règlements de swaps de taux d'intérêt	172	—
Distributions aux porteurs de parts	18 850	11 639
Impôts sur le capital et autres impôts	520	1 164

NOTE 8. ÉVÉNEMENT POSTÉRIEUR À LA DATE DU BILAN

Offre d'achat visant Great Northern Exploration Ltd.

Le 6 avril 2004, APF a conclu une entente afin de présenter une offre d'acquisition visant la totalité des actions émises et en circulation de Great Northern Exploration Ltd. (« Great Northern ») au prix de 5,05 \$ par action au comptant ou en contrepartie de 0,414614 part de Fiducie. Si elle est acceptée par les porteurs de toutes les actions de Great Northern, cette offre donnera lieu à une contrepartie totale d'environ 291 M\$ au comptant ou en parts de fiducie, en supposant la prise en charge de la dette bancaire de Great Northern. Cette offre est ouverte à des fins d'acceptation jusqu'au 1^{er} juin 2004.

Rapport de gestion

Le rapport de gestion doit être lu à la lumière des états financiers consolidés intermédiaires non vérifiés des trimestres terminés les 31 mars 2004 et 2003. Les informations financières ont été préparées selon les PCGR du Canada et sont présentées en dollars canadiens. Des informations supplémentaires liées à APF, notamment les exigences en matière d'informations à fournir en vertu de la norme canadienne 51-101 (la « NC 51-101 »), se trouvent dans la notice annuelle de 2003 d'APF (la « notice annuelle ») sur SEDAR (www.sedar.com) ou sur le site Web d'APF (www.apfenergy.com).

PRODUCTION

Les volumes de production se sont établis à 12 % de plus au premier trimestre de 2004 qu'à la période correspondante de 2003, ce qui témoigne des conséquences des acquisitions effectuées en 2003 et du succès remporté par le programme de forage. La baisse naturelle de la production du pétrole brut a été compensée par une augmentation de 31 % de la production de gaz naturel acquise pendant 2003, principalement par le truchement de l'acquisition de Nycan Energy Corp. (« Nycan ») et mise en valeur au moyen de programmes de forage fructueux à Countess et Enchant. La production du deuxième trimestre augmentera en raison de l'acquisition de Great Northern Exploration Ltd. (« Great Northern ») prévue pour le début de juin 2004. Au moment de l'annonce de l'acquisition, Great Northern produisait environ 5 600 bep/j.

	Trimestres terminés les 31 mars		Variation %
	2004	2003	
Pétrole brut (b/j)	6 104	6 345	(4)
Gaz naturel (kpi ³ /j)	37 729	28 745	31
LGN (b/j)	424	264	61
Total (bep/j)	12 816	11 400	12
Répartition de la production			
Pétrole et LGN	51 %	58 %	(12)
Gaz naturel	49 %	42 %	17

COMMERCIALISATION

Pendant le premier trimestre, la production d'APF était constituée à 51 % de pétrole brut et de LGN et à 49 % de gaz naturel. Le pétrole brut s'est vendu aux termes de contrats à tacite reconduction sur 30 jours alors qu'environ 25 % de la production de gaz naturel s'est vendue à des courtiers-fournisseurs aux termes de contrats à long terme, les 75 % restant ayant été vendus sur le marché au comptant.

PRIX

Au cours du premier trimestre de 2004, les réalisations du prix du pétrole brut ont diminué de 13 % par rapport à la période correspondante de 2003. Même si le prix de référence du West Texas Intermediate (« WTI ») a augmenté de 4 % par rapport au premier trimestre de 2003, le principal facteur à se répercuter sur les prix a été la diminution de 13 % de la valeur du dollar américain par rapport au dollar canadien pendant la même période. Les réalisations du gaz naturel au cours du trimestre ont diminué de 14 % par rapport à la période correspondante de 2003, le prix AECO régressant de 17 % par rapport à la période correspondante. Pour le reste de 2004, les contrats à terme NYMEX laissent entrevoir que le prix du pétrole brut dépassera les niveaux de 2003. APF prévoit que le prix du gaz en 2004 demeurera comparable aux niveaux de 2003, ou même les dépassera, alors que les préoccupations relatives à l'offre domineront le marché.

En date du 1^{er} janvier 2004, APF a séparé les coûts associés au transport et à la vente du pétrole brut, du gaz naturel et des LGN. Auparavant, elle suivait la pratique ayant cours dans le secteur, à savoir présenter les produits après déduction de ces coûts. Par conséquent, le 31 mars 2004, des états comparatifs ont été retraités après séparation de ces coûts, ce qui a donné lieu à une augmentation du prix brut par unité de production.

	Trimestres terminés les			
	31 mars			
				Variation
Prix – après opérations de couverture (\$ CA)	2004	2003		%
Pétrole brut (b)	35,06 \$	40,32 \$		(13)
Gaz naturel (kpi ³)	6,95	8,10		(14)
LGN (b)	33,80	38,41		(12)
Total	38,27 \$	43,76 \$		(13)
Prix de référence				
WTI (\$ US/b)	35,15 \$	33,86 \$		4
Gaz AECO (\$ CA/kpi ³)	6,60 \$	7,92 \$		(17)
Taux de change (\$ US/\$ CA)	1,318 \$	1,510 \$		(13)

INSTRUMENTS DÉRIVÉS

Le prix des marchandises est sensible aux fluctuations du marché. APF gère activement le risque lié au prix des marchandises au moyen de contrats de couverture qui mettent les produits à l'abri des fluctuations du prix des marchandises. Les opérations de couverture visent à stabiliser les niveaux de distribution en espèces au moyen de la fixation du prix des marchandises pour une partie du portefeuille de production. Le prix des marchandises est une des principales hypothèses utilisées pour dresser le budget annuel d'APF et estimer les distributions annuelles. APF a pour mandat d'assurer la protection d'une partie des distributions de l'année, lesquelles sont déterminées d'après les hypothèses relatives au prix des marchandises. APF recherche les occasions de vente à découvert d'une partie de sa production à des niveaux égaux ou supérieurs aux prix des marchandises utilisés dans le processus d'établissement du budget.

Bien que cette directive implique nécessairement une hausse du prix des marchandises, il ne faut pas oublier qu'il peut aussi baisser. À cet effet, lorsque le prix des marchandises est inférieur à celui utilisé pour établir le budget annuel, la direction, en se fondant sur son expérience, prend les mesures nécessaires pour atténuer l'incidence de la baisse du prix des marchandises. Au premier trimestre de 2004, les opérations de couverture ont réduit les produits qui auraient autrement été reçus de 1,0 M\$, ce qui a fait diminuer de 3,77 \$/b le prix obtenu pour le pétrole et fait augmenter le prix obtenu pour le gaz naturel de 0,31 \$/kpi³.

En date du 1^{er} janvier 2004, L'Institut Canadien des Comptables Agréés (l'« ICCA ») a publié la note d'orientation 13 concernant la comptabilité intitulée « Relations de couverture ». Conformément à ces nouvelles recommandations, il faut consigner les opérations de couverture et démontrer que les couvertures sont suffisamment efficaces pour appliquer la comptabilité de couverture. APF constatait auparavant seulement les gains et les pertes de couverture au fur et à mesure qu'ils se matérialisaient à la fin du contrat. Un examen des relations de couverture existantes a révélé que les couvertures visant les marchandises, les taux d'intérêt et le change d'APF ne sont pas admissibles à la comptabilité de couverture. Les gains et les pertes estimatifs sur les contrats ont été portés à l'état des résultats du trimestre se terminant le 31 mars 2004. Les couvertures de gaz naturel AECO d'APF sont effectivement admissibles; toutefois, la Fiducie a décidé de ne pas appliquer la comptabilité de couverture à ces instruments puisque la direction estime que, si elle appliquait la comptabilité de couverture à certaines opérations et non à d'autres, elle compromettrait la transparence de l'information financière et risquerait d'induire les lecteurs en erreur.

Au 1^{er} janvier 2004, APF a constaté une somme de 1,3 M\$ pour la valeur axée sur la valeur marchande des couvertures en vigueur comme s'il s'agissait d'un passif lié aux instruments dérivés et une perte reportée relative aux instruments dérivés de 1,3 M\$ devant se matérialiser au règlement des instruments dérivés correspondants. La perte reportée au 1^{er} janvier 2004 se composait d'une perte de 0,4 M\$ pour le pétrole brut et le gaz naturel et d'une perte de 0,9 M\$ pour des swaps de taux d'intérêt. Au 31 mars 2004, une tranche de 0,12 M\$ de la perte reportée a été constatée, le solde de 1,18 M\$ devant être constaté pendant le reste de 2004. Au 31 mars 2004, la juste valeur des instruments dérivés s'établissait à 4,44 M\$. Cette perte a été constatée comme un passif lié aux instruments dérivés, et une somme de 3,14 M\$ a été portée au poste des charges à l'état des résultats afin de tenir compte de la variation des justes valeurs depuis le 31 décembre 2003.

Au 31 mars 2004, APF disposait des couvertures suivantes :

Période	Marchandise	Type de contrat	Quantité quotidienne moyenne	Prix moyen de couverture
Avril à juin 2004	Pétrole brut	Swap	2 500 b	30,78 \$ US/b
Avril à juin 2004	Gaz naturel	Swap	10 333 GJ	5,76 \$ CA/GJ
Avril à juin 2004	Gaz naturel	Swap	1 000 Mbtu	5,19 \$ US/Mbtu
Juillet à septembre 2004	Pétrole brut	Swap	2 167 b	29,58 \$ US/b
Juillet à septembre 2004	Gaz naturel	Swap	10 000 GJ	5,75 \$ CA/GJ
Juillet à septembre 2004	Gaz naturel	Swap	1 000 Mbtu	5,19 \$ US/Mtu
Octobre à décembre 2004	Pétrole brut	Swap	1 833 b	30,45 \$ US/b
Octobre à décembre 2004	Gaz naturel	Swap	3 333 GJ	5,75 \$ CA/GJ
Octobre à décembre 2004	Gaz naturel	Swap	333 Mbtu	5,19 \$ US/Mbtu
Janvier 2005	Pétrole brut	Swap	1 000 b	31,74 \$ US/b

En plus des opérations de couverture du prix des marchandises, APF a aussi conclu des contrats de couverture de risque de change pour atténuer les risques liés au taux de change. La Fiducie a couvert 20 M\$ US de produits à un taux de 1,3317 \$ CA ou 0,7509 \$ US pour l'année civile 2004.

Au 31 décembre 2004, APF avait fixé le taux d'intérêt sur une partie de sa dette comme suit :

Durée	Montant (en milliers de dollars)	Taux d'intérêt
Avril 2004 à mars 2007	20 000 \$	3,58 %, majoré d'une commission d'acceptation
Avril 2004 à mai 2006	20 000 \$	3,60 %, majoré d'une commission d'acceptation
Avril 2004 à novembre 2005	20 000 \$	3,58 %, majoré d'une commission d'acceptation

PRODUITS

Pétrole et gaz (en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars			
	2004	Pourcentage du total	Retraité 2003	Pourcentage du total
Ventes de pétrole brut	21 569 \$	49	25 107	56
Ventes de gaz naturel	22 783	51	21 228	48
Ventes de LGN	1 305	3	914	2
Couverture du prix des marchandises	(1 027)	(2)	(2 345)	(5)
Transports	(865)	(1)	(811)	(1)
Autres	698	1	409	1
Total des produits	44 463 \$	100	44 502 \$	100
Par bep	38,12 \$		43,37 \$	

Les produits du premier trimestre de 2004, déduction faite de la couverture, ont été comparables à ceux du premier trimestre de 2003 en s'établissant à 44 M\$. La hausse des produits tirés du gaz naturel a compté pour 51 % du total des produits du premier trimestre de 2004, soit une augmentation de 1,6 M\$ par rapport à la période correspondante de l'exercice précédent. Les produits tirés de la vente du pétrole brut ont reculé de 3,5 M\$ depuis le premier trimestre de 2003 à la suite de la baisse de la production et des prix réalisés. En date du 1^{er} janvier 2004, APF a séparé les coûts associés au transport et à la vente du pétrole brut, du gaz naturel et des LGN. Auparavant, elle suivait la pratique ayant cours dans le secteur, à savoir présenter les produits après déduction de ces coûts. Par conséquent, les états comparatifs au 31 mars 2003 ont été retraités pour tenir compte de cette séparation.

REDEVANCES

Au premier trimestre, le total des redevances en pourcentage des produits demeurait au taux constant de 20,0 %. Les redevances par baril d'équivalent pétrole ont diminué de 12 % en 2004 par suite de l'évolution du portefeuille de propriétés et des redevances à payer.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation
	2004	2003	%
Redevances à la Couronne	5 426 \$	5 135 \$	6
Redevances de propriétaire franc	2 773	3 112	(11)
Redevances dérogatoires	858	845	2
Total des redevances	9 057 \$	9 092 \$	—
En pourcentage des produits, après opérations de couverture	20,0 %	20,1 %	—
Par bep	7,77 \$	8,86 \$	(12)

CHARGES D'EXPLOITATION

Au quatrième trimestre, les charges d'exploitation par bep se sont accrues de 17 % par rapport à la même période en 2003, passant de 6,55 \$ à 7,64 \$. Ces hausses sont surtout attribuables aux coûts d'optimisation des champs liés aux nouvelles propriétés d'APF ainsi qu'aux charges d'énergie plus élevées. Selon les prévisions, l'augmentation des charges d'énergie ainsi que l'accroissement des frais aux champs à l'égard du portefeuille actuel de propriétés d'APF devraient annuler tout gain d'efficacité de l'exploitation découlant des mesures prises pour comprimer les charges d'exploitation au deuxième et au troisième trimestres de 2004.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation
	2004	Retraité 2003	%
Charges d'exploitation	8 910 \$	6 719 \$	33
Par bep	7,64 \$	6,55 \$	17

REVENU NET

Le revenu net tiré de l'exploitation par bep a diminué de 19 % par rapport à la période correspondante de 2003 en raison, à la fois, d'une baisse des prix et d'une augmentation des charges d'exploitation, facteurs qui ont été partiellement compensés par une réduction des redevances par baril d'équivalent pétrole.

(\$/bep)	Trimestres terminés les 31 mars		Variation
	2004	2003	%
Produit net (après les opérations de couverture)	38,12 \$	43,37 \$	(11)
Redevances	(7,77)	(8,86)	(12)
Charges d'exploitation	(7,64)	(6,55)	17
Revenu net	22,71 \$	27,96 \$	(17)

FRAIS GÉNÉRAUX ET ADMINISTRATIFS

Les frais généraux et administratifs ont augmenté en chiffres absolus et par bep par rapport à la période correspondante de 2003. Cette hausse est imputable à l'accroissement des coûts liés à l'effectif, qui témoigne de l'accroissement de la taille de l'entreprise d'APF.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation %
	2004	2003	
Charges d'exploitation	1 839 \$	1 374 \$	34
Par bep	1,58 \$	1,34 \$	18

INTÉRÊTS

Les intérêts débiteurs ont diminué en chiffres absolus et par bep comparativement à la période correspondante de 2003 en raison de la baisse de la dette, qui est passée de 97 M\$ au trimestre terminé le 31 mars 2003 à 55 M\$ au trimestre correspondant de 2004.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation %
	2004	2003	
Intérêts débiteurs	977 \$	1 153 \$	(15)
Par bep	0,84 \$	1,12 \$	(25)

ÉPUISEMENT, AMORTISSEMENT ET DÉSACTUALISATION

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		Variation %
	2004	Retraité 2003	
Épuisement, amortissement et désactualisation	17 033 \$	10 540 \$	62
Par bep	14,60 \$	10,16 \$	44

L'épuisement, amortissement et désactualisation a augmenté de 62 % par bep au premier trimestre de 2004 par rapport à la période correspondante de 2003. Cette augmentation par rapport à l'exercice précédent est attribuable à l'accroissement du chiffre inscrit au poste des immobilisations en raison de l'adoption de l'obligation liée à la mise hors service d'immobilisations et de l'acquisition d'entreprises en 2003. Le chiffre correspondant inscrit au 31 mars 2003 au poste de l'épuisement, amortissement et désactualisation a été retraité pour tenir compte de l'adoption de l'obligation liée à la mise hors service d'immobilisations.

OBLIGATIONS LIÉES À LA MISE HORS SERVICE D'IMMOBILISATIONS

Pendant le premier trimestre, APF a adopté le chapitre 3110 du Manuel de L'Institut Canadien des Comptables Agréés (l'« ICCA ») intitulé « Obligations liées à la mise hors service d'immobilisations ». Cette modification de convention comptable a été appliquée rétroactivement, et les périodes antérieures présentées à des fins de comparaison ont été retraitées. Auparavant, APF constatait une provision pour coûts futurs de restauration et d'abandon des lieux calculée selon la méthode de l'amortissement proportionnel à l'utilisation, sur la durée des propriétés pétrolières et gazières, compte tenu du total des réserves prouvées estimatives, et un passif futur estimatif.

La direction a estimé l'obligation totale future liée à la mise hors service d'immobilisations en fonction de la participation d'APF dans tous les puits et toutes les installations. Cette estimation tient compte des coûts nécessaires à l'abandon et à la restauration des puits et des installations ainsi que du calendrier estimatif de ces activités de restauration des lieux.

En raison de l'adoption de cette nouvelle norme, au 31 décembre 2003, l'obligation liée à la mise hors service des immobilisations a été portée à 21,80 M\$, les immobilisations après déduction de l'épuisement cumulé ont augmenté de 12,42 M\$ et le passif d'impôts futurs a reculé de 0,23 M\$. Les bénéfices non répartis à l'ouverture, au 1^{er} janvier 2004, ont augmenté de 1,26 M\$ en raison de l'effet cumulatif des charges de désactualisation et d'épuisement, déduction faite de la provision cumulative pour la restauration des lieux et impôts sur les bénéfices futurs, sur l'obligation liée à la mise hors service d'immobilisations constatée rétroactivement jusqu'en 1996, soit l'année d'établissement de la Fiducie.

L'obligation liée à la mise hors service d'immobilisations a augmenté de 44 % par rapport au 31 mars 2003. Cette augmentation est principalement attribuable à l'acquisition des entreprises de Hawk, Nycan et CanScot pendant l'exercice ainsi qu'à la désactualisation de l'obligation liée à la mise hors service d'immobilisations visant à tenir compte du passage du temps.

(en milliers de dollars)	Trimestres terminés les 31 mars		Variation %
	2004	Retraité 2003	
Obligations liées à la mise hors service d'immobilisations	22 187 \$	15 398 \$	44

CHARGE DE RÉMUNÉRATION

APF a adopté prospectivement le chapitre 3870 du Manuel de l'ICCA intitulé « Rémunérations et autres paiements à base d'actions ». Selon les dispositions provisoires qui y sont contenues, les entités qui les ont adoptées prospectivement au 31 décembre 2003 ne doivent que constater la charge de rémunération liée aux options attribuées en 2003 et doivent présenter les données pro forma sur les options accordées en 2002. Puisque APF octroie des droits seulement une fois par année, soit au deuxième trimestre, la charge de rémunération constatée pendant le premier trimestre de 2004 concerne uniquement des droits octroyés en 2003. La charge de rémunération au 31 mars 2003 a été retraitée puisque la norme a été adoptée pendant le quatrième trimestre de 2003.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars	
	2004	Retraité 2003
Charge de rémunération	257 \$	8 \$
Par bep	0,22 \$	0,01 \$

IMPÔTS

L'impôt sur le capital de la Saskatchewan et l'impôt fédéral des grandes sociétés ont diminué de 28 % pendant le trimestre, comparativement à 2003, en raison d'une réduction des taux de l'impôt sur le capital pendant la période correspondante.

Les impôts sur les bénéfices futurs sont inscrits dans la mesure où la valeur comptable des actifs acquis, excluant l'écart d'acquisition, excède leur valeur fiscale. Ces passifs d'impôts futurs font augmenter la valeur comptable des actifs acquis. Il est prévu que les passifs d'impôts futurs ne seront pas payés par APF Energy, mais seront plutôt transférés aux porteurs de parts au même titre que le revenu. En conséquence, les passifs d'impôts futurs diminueront chaque année et ils seront alors constatés à titre d'économie d'impôts à ce moment, dans la mesure où aucun impôt sur les bénéfices n'a été payé par APF Energy. Pendant le premier trimestre, l'économie d'impôts sur les bénéfices s'est chiffrée à 5,6 M\$, en regard de charges d'impôts futurs (retraité) de 1,09 M\$ en 2003, pour un solde de 58,6 M\$ des impôts sur les bénéfices futurs payables au 31 mars 2004. Les impôts sur les bénéfices futurs de 2003 ont été retraités pour tenir compte de l'adoption de l'obligation liée à la mise hors service d'immobilisations. Au 31 décembre 2003, ce retraitement a eu pour effet de diminuer de 0,23 M\$ les impôts sur les bénéfices futurs.

(en milliers de dollars, sauf les montants par bep)	Trimestres terminés les 31 mars		
	2004	Retraité 2003	Variation %
Impôts sur le capital et autres impôts	605 \$	836 \$	(28)
Par bep	0,52 \$	0,81 \$	(36)
Charge (économie) d'impôts sur les bénéfices futurs	(5 607) \$	1 093 \$	613

BÉNÉFICE NET

Le bénéfice a diminué de 41 % pour s'établir à 8,1 M\$ ou 0,19 \$ par part de fiducie (bénéfice dilué par part de 0,19 \$) au 31 mars 2004, comparativement à 13,7 M\$ ou 0,54 \$ par part de fiducie (bénéfice dilué par part de 0,54 \$) au 31 mars 2003. Cette diminution est imputable à la réduction du revenu net tiré de l'exploitation, à l'obligation liée à la mise hors service d'immobilisations s'appliquant à l'épuisement, amortissement et désactualisation, et à la constatation d'une perte sur instruments dérivés au 31 mars 2004.

RÉSUMÉ DES RÉSULTATS TRIMESTRIELS

(en milliers de dollars, sauf les montants par part)	2004	2003 (retraité)				2002 (retraité)			
	T1 \$	T1 \$	T2 \$	T3 \$	T4 \$	T1 \$	T2 \$	T3 \$	T4 \$
Produits	46 355	47 658	41 876	39 970	39 110	16 941	21 495	26 204	29 380
Bénéfice net	8 127	13 687	21 195	11 552	(3 166)	2 444	4 459	5 493	(942)
Par part – de base (en dollars)	0,19	0,54	0,66	0,32	(0,09)	0,14	0,22	0,25	(0,04)
Par part – dilué (en dollars)	0,19	0,54	0,65	0,31	(0,09)	0,14	0,22	0,25	(0,04)

Les produits ont augmenté en proportion de la production qui est attribuable aux initiatives de mise en valeur et aux acquisitions d'entreprises en 2002 et en 2003. Le bénéfice a diminué en raison de l'augmentation de l'épuisement, amortissement et désactualisation, de l'effet sur l'obligation liée à la mise hors service d'immobilisations sur l'épuisement, amortissement et désactualisation et de la constatation des pertes de couverture pendant le premier trimestre de 2004. La perte constatée pendant le quatrième trimestre de 2003 est imputable aux conséquences du régime d'intéressement à court terme ainsi qu'à la réduction des prix des marchandises, lesquels se sont ressaisis au cours du premier trimestre de 2004.

DÉPENSES EN IMMOBILISATIONS, ACQUISITIONS ET CESSIONS

Le montant net des dépenses en immobilisations s'est établi à 12,6 M\$ au premier trimestre, comparativement à 63,0 M\$ au premier trimestre de 2003. Au premier trimestre, APF a dépensé 11,8 M\$ du programme de dépenses en immobilisations budgété de 40,0 M\$, principalement dans le centre de l'Alberta et dans le sud-est de la Saskatchewan. Une fois l'acquisition de Great Northern terminée, APF s'attend à enregistrer une légère hausse de son programme de dépenses en immobilisations qui sera financé à la fois au moyen des flux de trésorerie, du produit tiré du réinvestissement des distributions et de la dette.

(en milliers de dollars)	Trimestres terminés les 31 mars	
	2004	2003
Acquisitions de sociétés	– \$	57 146 \$
Acquisition de propriétés	925	323
Acquisitions de terrains	1 432	315
Sismique	734	204
Forage et compléments de puits	7 560	3 961
Installations de production	1 829	1 004
Autres	280	83
Total partiel	12 760 \$	63 036 \$
Cessions	(199)	–
Dépenses en immobilisations, montant net	12 561 \$	63 036 \$

DISTRIBUTIONS EN ESPÈCES

Les distributions en espèces se sont élevées à 19,8 M\$, ou 0,525 \$ par part de fiducie, au premier trimestre de 2004, contre 13,1 M\$ ou 0,510 \$ par part de fiducie pour la période correspondante de 2003. Pendant le premier trimestre, APF a financé 1,5 M\$ des dépenses en immobilisations à partir de ses flux de trésorerie (5,57 M\$ en 2003), ce qui a produit un ratio de distribution de 92 % (51 % en 2003), compte tenu des intérêts cumulés sur les débentures convertibles. Pour le reste de 2004, APF a l'intention d'appliquer la même politique qu'elle a appliquée par le passé en matière de distributions, c'est-à-dire de conserver une partie des flux de trésorerie disponibles pour l'affecter au financement des dépenses en immobilisations et des projets de mise en valeur, son objectif étant de maintenir un ratio de 10 % à 20 %.

LIQUIDITÉS ET RESSOURCES EN CAPITAL

Au 31 mars 2004, APF avait une facilité de crédit à terme renouvelable de 150 M\$, sur laquelle 55 M\$ ont été prélevés (97 M\$ en 2003). Il est possible de faire des prélèvements sur la facilité de crédit ou de la rembourser en tout temps, et aucun calendrier de remboursement n'a été établi. Après l'achat de Great Northern, APF s'attend à ce que les modalités de la facilité soient modifiées pour tenir compte de la nouvelle base de réserves, puisque les prêteurs auront terminé leur revue annuelle, d'ici le 30 juin 2004.

Au 31 mars 2004, le solde des débentures convertibles, déduction faite des conversions, s'établissait à 46,3 M\$.

Au 31 mars 2004, APF accusait un déficit du fonds de roulement d'environ 6,1 M\$ contre un surplus de 10,2 M\$ au 31 décembre 2003. Le fonds de roulement déficitaire est principalement imputable à l'intensification des activités aux champs pendant l'hiver, période au cours de laquelle une partie importante des initiatives de forage et d'optimisation ont pris fin. Le produit tiré en février du financement par actions a servi à rembourser la dette et à combler partiellement le fonds de roulement déficitaire.

CAPITAUX PROPRES

Au 31 mars 2004, 39,7 millions de parts de fiducie d'APF étaient en circulation (27,0 millions en 2003), et sa capitalisation boursière s'établissait à environ 487 M\$ (278 M\$ en 2003).

Pendant le premier trimestre, APF a émis 744 692 parts de fiducie aux termes du régime de réinvestissement des distributions de primes pour un produit de 8,5 M\$ (néant en 2003).

Le 4 février 2004, APF a procédé à la clôture de l'émission de 4,77 millions de parts de fiducie à un prix de 11,60 \$ chacune pour un produit brut de 55,3 M\$. Le produit de ce placement a servi à financer le fonds de roulement et à rembourser la dette.

RISQUES COMMERCIAUX

APF est exposée à de nombreux risques inhérents au secteur du pétrole et du gaz. Ces risques pourraient avoir une incidence sur les distributions aux porteurs de parts. Pour réduire son exposition à ces risques, APF respecte des politiques et des procédures appropriées dans le cadre de ses activités quotidiennes et de sa planification stratégique à long terme.

Les risques financiers et les risques du marché liés aux fluctuations du prix des marchandises et des taux de change sont atténués au moyen de la gestion active par APF de la vente de sa propre production afin d'accroître au maximum les prix et au moyen d'un programme de couverture du prix des marchandises et des taux de change avec des contreparties solvables. APF a recours à des couvertures en tant qu'outils de gestion des risques et non pas à des fins de spéculation.

Des risques d'exploitation sont associés à la production de pétrole et de gaz naturel, en ce qui concerne la capacité de production, de traitement et de transport du pétrole et du gaz naturel, la capacité de remplacer la production et de conserver les réserves ainsi que les risques sur le plan de l'environnement et de la sécurité liés aux puits et aux installations de production. Pour atténuer ces risques, APF a recours à une stratégie d'exploitation pour une importante partie de sa production, ce qui lui procure un plus grand contrôle sur ses activités. APF engage des employés et des entrepreneurs qui respectent son programme de sécurité et qui s'informent régulièrement des pratiques en matière d'exploitation. En outre, APF conserve une assurance en vue de réduire les conséquences des pertes d'exploitation.

La croissance d'APF est fonction de sa capacité d'obtenir du financement par emprunt ou par actions sur les marchés financiers canadiens. APF dispose de marges de crédit auprès de trois banques à charte canadiennes. Celles-ci lui permettent de financer par emprunt ses acquisitions. Grâce à l'émission de nouveaux titres, APF est en mesure de rembourser sa dette tout en continuant de procéder à des acquisitions. Si APF n'avait plus accès aux marchés canadiens de la dette et des actions, elle pourrait avoir de la difficulté à remplacer sa production et à effectuer ses distributions.

Les changements apportés aux règlements gouvernementaux en matière de redevances, aux lois fiscales, aux programmes d'encouragement lié au secteur du pétrole et du gaz et aux lois sur les valeurs mobilières sont des exemples de modifications réglementaires qui peuvent influencer sur les activités d'APF.

Les changements apportés à de nombreuses variables ont une influence sur les flux de trésorerie d'APF. La sensibilité des flux de trésorerie avant couverture de 2004 s'établit comme suit :

Variable	Variation	Incidence sur les flux de trésorerie (en milliers de dollars)	Incidence par part
Prix du pétrole brut	1 \$ US par baril	2 360	0,07 \$
Prix du gaz naturel	0,10 \$ CA/kp ³	1 200	0,04 \$
Taux de change \$ US/\$ CA	0,01 \$	2 000	0,06 \$
Taux d'intérêt	1,00 %	1 000	0,03 \$
Production de pétrole brut	100 barils par jour	1 095	0,03 \$
Production de gaz naturel	1 Mp ³ par jour	1 500	0,04 \$

ESTIMATIONS COMPTABLES CRUCIALES

Pour dresser les états financiers conformément aux PCGR du Canada, APF doit faire des estimations et poser des hypothèses. Les questions décrites ci-après sont considérées comme cruciales pour comprendre les jugements posés pour préparer les états financiers ainsi que les incertitudes qui pourraient se répercuter sur les montants présentés au sujet des résultats d'exploitation, de la situation financière et des flux de trésorerie. Les conventions comptables sont décrites à la note 2 afférente aux états financiers vérifiés datés du 31 décembre 2003.

ESTIMATION DES RÉSERVES DE PÉTROLE ET DE GAZ

Les réserves de pétrole et de gaz ont été estimées conformément à la NC 51-101. De par leur nature, les estimations des réserves de pétrole et de gaz sont imprécises et ne représentent que des montants approximatifs. Elles sont de plus soumises à une révision future puisqu'elles sont déterminées d'après les données, les prix et les coûts disponibles sur les réservoirs au moment où ces estimations sont effectuées. En conséquence, les mesures financières établies en fonction des réserves estimatives peuvent aussi être modifiées.

ÉPUISEMENT ET AMORTISSEMENT

Les réserves prouvées sont utilisées dans les taux d'amortissement proportionnel au rendement pour calculer l'épuisement et l'amortissement des biens liés au pétrole et au gaz, notamment les immobilisations corporelles liées aux activités de production d'hydrocarbures. Le montant de l'amortissement est fonction des unités de production sur les réserves prouvées et mises en valeur du champ pertinent au cours de la période. Les propriétés non prouvées sont amorties selon les circonstances. Les autres immobilisations corporelles sont généralement amorties au moyen de la méthode de l'amortissement linéaire sur leur durée de vie utile de cinq à dix ans.

PLAFONNEMENT DU COÛT ENTIER

La valeur comptable des immobilisations est examinée pour déceler toute perte de valeur lorsque des faits ou des changements de circonstances laissent supposer que la valeur comptable de ces propriétés risque de ne pas être recouvrable. S'il est déterminé que les actifs ont subi une perte de valeur, leur valeur comptable est ramenée à la juste valeur. À cette fin, les actifs sont attribués à un centre de coûts selon le pays dans lequel l'activité s'est déroulée. Les estimations des flux de trésorerie futurs des actifs liés aux activités de production d'hydrocarbure sont déterminées d'après les réserves prouvées établies conformément à la NC 51-101.

FRAIS DE RESTAURATION ET D'ABANDON DES LIEUX

Des provisions sont constituées pour l'abandon et la restauration futurs des installations de production de pétrole et de gaz naturel et les pipelines à la fin de leur durée économique. Les frais de restauration et d'abandon des lieux sont déterminés d'après les exigences, la technologie et le niveau des prix actuels. La plupart de ces obligations s'étalent sur plusieurs années dans le futur et les exigences précises auxquelles nous devons satisfaire sont incertaines puisque les technologies et les coûts ainsi que les attentes sur les plans de la politique, de l'environnement et de la sécurité peuvent changer.

CHANGEMENTS RÉCENTS DE CONVENTIONS COMPTABLES OU DE RÈGLEMENTS

Obligations liées à la mise hors service d'immobilisations

L'Institut Canadien des Comptables Agréés (l'« ICCA ») a publié le chapitre 3110, « Obligations liées à la mise hors service d'immobilisations » en mars 2003. Conformément à cette nouvelle norme, les entités doivent constater l'obligation liée aux coûts futurs de restauration des lieux dans les états financiers. Cette nouvelle norme canadienne s'appliquera aux exercices débutant à compter du 1^{er} janvier 2004.

Conformément à cette norme, ces obligations sont d'abord mesurées à la juste valeur, puis ajustées pour tenir compte de la désactualisation et de la variation des flux de trésorerie sous-jacents. Le coût lié à la mise hors service d'immobilisations est capitalisé sur l'actif s'y rattachant et imputé aux résultats sur la durée de vie des actifs.

APF a adopté cette nouvelle norme au cours du premier trimestre et retraité rétroactivement les périodes antérieures, comme l'exigent les PCGR. Voir les notes 2 et 4 afférentes aux états financiers non vérifiés datés du 31 mars 2004 qui décrivent les conséquences de l'adoption de cette nouvelle norme.

Comptabilisation des instruments dérivés

En date du 1^{er} janvier 2004, APF a adopté la note d'orientation 13 de l'ICCA intitulée « Relations de couverture », qui traite de l'identification, de la désignation, de la consignation et de la mesure de l'efficacité des relations de couverture, aux fins de l'application de la comptabilité de couverture. Cette note s'applique aux exercices ouverts à compter du 1^{er} juillet 2003.

Cette nouvelle note aborde les opérations de couverture aux fins de l'application de la comptabilité de couverture en plus d'en établir les conditions d'application. Conformément à ces nouvelles recommandations, il faut consigner les opérations de couverture et démontrer que les couvertures sont suffisamment efficaces pour appliquer la comptabilité de couverture aux positions couvertes au moyen d'instruments dérivés. APF n'applique pas la comptabilité de couverture à ses relations d'instruments dérivés. Voir les notes 2 et 5 afférentes aux états financiers non vérifiés datés du 31 mars 2004 qui décrivent les conséquences de l'adoption de cette nouvelle norme.

Obligations d'information continue

Dès le 31 mars 2004, tous les émetteurs assujettis au Canada seront assujettis à de nouvelles exigences en matière d'obligations d'information continue conformément à la norme canadienne 51-102, « Obligations d'information continue ». Cette nouvelle norme s'applique aux exercices débutant à compter du 1^{er} janvier 2004. Cette norme propose des périodes de déclaration plus courtes pour le dépôt des états financiers annuels ou intermédiaires, des rapports de gestion et des notices annuelles.

Cette norme propose également de présenter davantage d'informations dans les états financiers et les rapports de gestion annuels ou intermédiaires et dans les notices annuelles. Selon cette nouvelle norme, il ne sera dorénavant plus obligatoire pour APF de poster les états financiers et rapports de gestion annuels ou intermédiaires aux porteurs de parts. Cependant, ces documents seront fournis sur demande.

Entités à détenteurs de droits variables

En juin 2003, l'ICCA a publié la note d'orientation comptable n° 15, « Consolidation des entités à détenteurs de droits variables », qui traite de la consolidation de certaines entités sur lesquelles le contrôle s'exerce autrement que par l'exercice des droits de vote. Cette note s'applique aux périodes annuelles et intermédiaires débutant à compter du 1^{er} novembre 2004. APF évalue actuellement l'incidence de ces nouvelles recommandations.

Comptabilisation des débentures convertibles

En juin 2003, l'ICCA a approuvé la modification du chapitre 3860 du Manuel intitulé « Instruments financiers – informations à fournir et présentation ». Conformément aux recommandations précédentes, les créances qui pouvaient être réglées au moyen des instruments de capitaux propres de l'entité pouvaient être classées à titre de capitaux propres, et les intérêts connexes étaient traités comme une réduction des capitaux propres.

Cette modification exige que certaines créances devant ou pouvant être réglées à l'aide des instruments de capitaux propres de l'entité soient présentées à titre de passif, les intérêts correspondants étant inscrits à l'état des résultats. Elle s'applique aux exercices débutant après le 1^{er} novembre 2004.

PERSPECTIVES

APF demeure engagée envers sa stratégie qui consiste à acheter des puits et à exploiter son patrimoine de propriétés au moyen de forages de développement, de remises en production et d'optimisations de champs. Pour 2004, elle a prévu forer 167 puits bruts au total. APF a attribué 40 M\$ au budget de ses dépenses en immobilisations pour l'exercice (compte non tenu des zones d'intérêt situées dans les terrains de Great Northern), 85 % des fonds étant consacrés au forage et à la mise en valeur de propriétés classiques. Au cours de 2004, APF poursuivra l'expansion de ses projets pilotes de gaz de gisements houillers dans le centre de l'Alberta. Au total, 7 M\$ ont été prévus au budget des dépenses en immobilisations pour les initiatives de gaz de gisements houillers au Canada et aux États-Unis. Avec une faible baisse de la production et la possibilité de générer des rendements plus élevés que ceux de la production classique, APF est d'avis que le gaz de gisements houillers représente une occasion très intéressante et idéale pour la structure de la Fiducie.

APF continuera de procéder à des acquisitions qui contribueront à améliorer, par part, les flux de trésorerie, la production, les réserves et la valeur liquidative d'APF. Cette dernière s'est engagée à préserver la stabilité à long terme des distributions en espèces. Pour atténuer les risques liés aux fluctuations du prix des marchandises qui sont inhérents au secteur du pétrole et du gaz naturel, APF couvrira activement sa production. À long terme, APF estime que les prix du pétrole brut et du gaz naturel se maintiendront à un niveau élevé.

Énoncés prospectifs

Certains énoncés contenus dans le présent document sont des « énoncés prospectifs », notamment les perspectives sur les prix du pétrole et du gaz, les redevances, les charges d'exploitation, les estimations de la production future, les dates d'achèvement estimatives des projets de construction et de mise en valeur, les plans d'affaires pour le forage et l'exploration, les montants estimatifs des dépenses en immobilisations et le moment où elles seront effectuées ainsi que les niveaux d'endettement futurs prévus. Les informations sur les réserves contenues dans ce document peuvent aussi être considérées comme des énoncés prospectifs puisque ces estimations comportent l'idée qu'il est possible de produire les ressources décrites de manière rentable. Les projections, les estimations et les opinions présentées dans ces énoncés prospectifs comportent forcément des risques et des incertitudes qui pourraient faire en sorte que les résultats financiers futurs réels diffèrent sensiblement des projections d'APF Energy Trust et d'APF Energy Inc. Ces risques incluent notamment : les risques liés au secteur du pétrole et du gaz (comme les risques d'exploitation liés à l'exploration; la mise en valeur et la production de pétrole brut et de gaz naturel; les risques et les incertitudes comportant la géologie des gisements de pétrole et de gaz; l'incertitude des estimations reliées aux réserves; l'incertitude des estimations et des projections concernant la production, les coûts et les charges; les délais possibles ou les changements de plans à l'égard des projets d'exploration ou de mise en valeur ou des dépenses en immobilisations et les risques liés à la santé, à la sécurité et à l'environnement); les risques liés à l'exécution des activités exercées à l'étranger (comme l'instabilité politique et budgétaire dans les pays où APF Energy fait des affaires); la possibilité que les politiques gouvernementales changent ou que les approbations des gouvernements soient retardées ou retenues et les fluctuations des prix et du taux de change. Ces risques et d'autres sont décrits dans les rapports d'APF Energy qui sont déposés auprès des organismes de réglementation des valeurs mobilières. Il n'est pas possible de déterminer avec certitude l'incidence d'un seul facteur sur un énoncé prospectif en particulier puisque ces facteurs sont dépendants d'autres facteurs et que la mesure qu'adoptera la direction dépendra de son évaluation de l'avenir compte tenu de toutes les informations dont elle dispose alors. Les lecteurs sont prévenus que la liste ci-dessus des facteurs importants n'est pas exhaustive. Bien que la société estime que les attentes contenues dans les énoncés prospectifs sont raisonnables d'après les informations disponibles au moment où elle les a formulées, aucune assurance ne peut être donnée quant aux résultats, aux niveaux d'activités et aux réalisations futurs. Tous les énoncés prospectifs subséquents, qu'ils soient présentés par écrit ou oralement, attribuables à APF ou à toute personne agissant en son nom sont expressément présentés sous réserve de cette mise en garde. APF n'a pas l'obligation de mettre à jour les énoncés prospectifs contenus aux présentes advenant un changement de circonstances, d'estimations ou d'opinions de la direction.



NEWS RELEASE

TSX: AY.UN; AY.DB

APF Energy announces plans to increase capital expenditure program

Trust also announces July cash distribution

June 21, 2004. APF Energy Trust announces that it will be increasing its 2004 capital expenditure program, as a result of its recent acquisition of Great Northern Exploration Ltd. and additional prospects identified on its own lands. Details of the new program will be outlined in conjunction with the release of APF's interim report for the second quarter, due out the week of August 9, 2004.

"Our strategy continues to be one of increasing our focus on growth through the drill bit", commented APF's President, Steve Cloutier. "As we stated when we agreed to buy Great Northern, our goal is to position APF with several years of prospects that can add production and reserves at more favourable rates than through acquisitions." Mr. Cloutier added: "Our technical team hit the ground running on Great Northern's drilling inventory so we're optimistic that other opportunities will surface."

In order to fund the increased capital program, APF intends to retain a greater portion of its cash flow. Accordingly, APF's next distribution will be \$0.16 per unit, payable on July 15, 2004 to unitholders of record on June 30, 2004. The ex-distribution date is June 28, 2004.

"While we were reluctant to reduce our monthly distribution, we felt that the long-term benefits of funding a greater portion of our capital program through cash flow outweighed the near-term effects", stated Mr. Cloutier.

APF estimates that the more conservative payout ratio will return the Trust to a range within which it has operated since inception. Over the last four years, APF has had one of the sector's best development track records, replacing, on average 106% of annual production through drilling and other production enhancement techniques. APF has been among the industry leaders in funding a significant portion of its capital program through cash flow.

APF Energy Trust is a conventional oil and gas royalty trust with interests in producing assets in Alberta, Saskatchewan and Wyoming. Since inception in 1996, the Trust has generated a compound annual return of 22% and has been one of the top performing royalty trusts listed on the Toronto Stock Exchange.

Certain statements in this material may be "forward-looking statements" including outlook on oil and gas prices, estimates of future production, estimated completion dates of acquisitions and construction and development projects, business plans for drilling and exploration, estimated amount and timing of capital expenditures and anticipated future debt levels and royalty rates. Information concerning reserves contained in this material may also be deemed forward-looking statements as such estimates involve the implied assessment that the resources described can be profitably produced in the future. These statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated by APF. This news release is not for distribution in the U.S. The Toronto Stock Exchange has neither approved nor disapproved of the contents of this news release.

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