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82- SUBMISSIONS FACING SHEET

Follow-Up Materials

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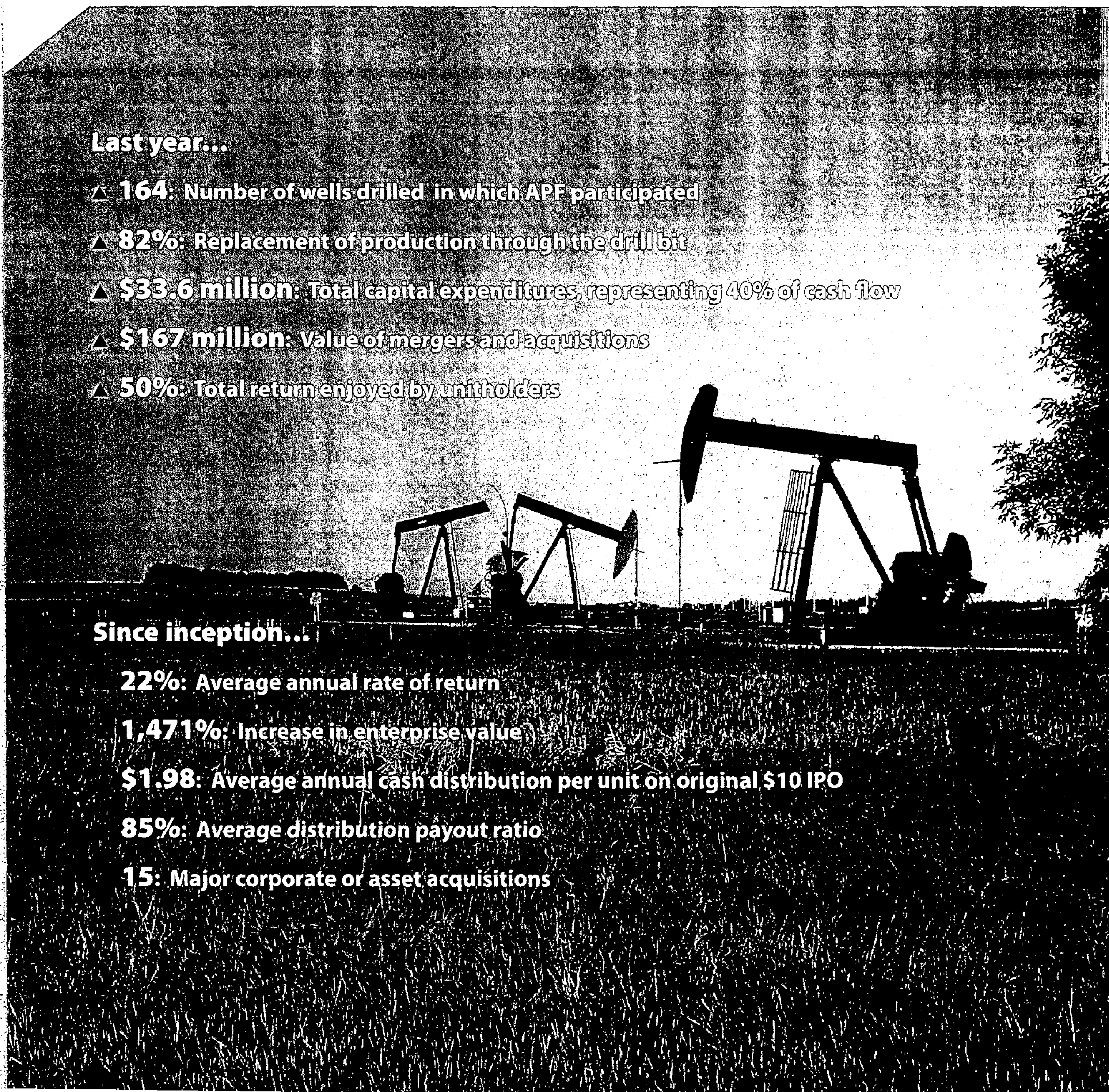
APF ENERGY TRUST

82-5766

ARIS
12-31-03

2003
ANNUAL REPORT

By the Numbers



Last year...

- **164:** Number of wells drilled in which APF participated
- **82%:** Replacement of production through the drill bit
- **$33.6 million:** Total capital expenditures, representing 40% of cash flow
- **$167 million:** Value of mergers and acquisitions
- **50%:** Total return enjoyed by unitholders

Since inception...

22%: Average annual rate of return

1,471%: Increase in enterprise value

$1.98: Average annual cash distribution per unit on original $10 IPO

85%: Average distribution payout ratio

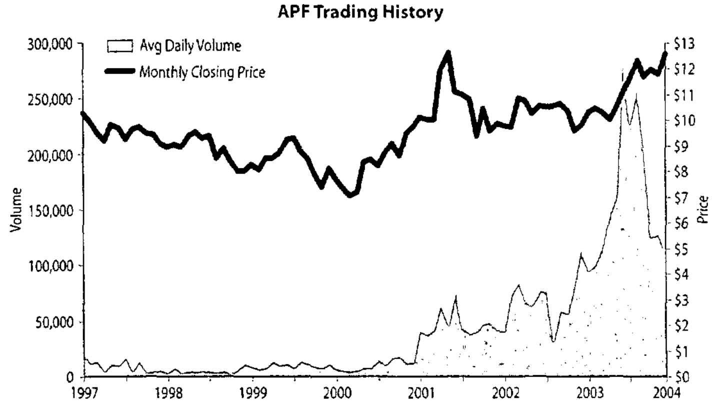
15: Major corporate or asset acquisitions

APF Energy Trust is a dynamic, growth-oriented royalty trust created in December, 1996 to provide unitholders with stable distributions based on cash flow generated from high quality oil and gas properties. Through strong acquisitions and effective optimization initiatives, APF has increased production by more than 665%, from 1,700 boe/d in the fourth quarter of 1996 to more than 13,000 boe/d at December, 2003. Since completing its initial public offering at $10 per unit, the Trust has declared cumulative distributions of $13.83 per unit to December, 2003, rewarding unitholders with an average annual return of 22%.

TRADING HISTORY

APF Energy Trust units ("AY.UN") and convertible debentures ("AY.DB") are traded on the Toronto Stock Exchange. Average daily trading volumes for the units increased by 137% from 67,000 in 2002 to 163,000 in 2003. The following graph illustrates trading in APF's units since inception.

APF Trading History



ANNUAL AND SPECIAL MEETING

The Annual and Special Meeting of the Unitholders of APF Energy Trust will be held on May 18, 2004 at 3:00 pm in the Roxy Theatre at the Sun Life Conference Centre (mezzanine level), 140 – 4th Avenue S.W., Calgary, Alberta.

CONTENTS

Summary of Operating and Financial Results

Year Ended December 31	2003	2002	% Change
Financial			
($000, except per unit/boe amounts)			
Revenue	**165,457**	94,021	76%
Per unit basic	**$5.34**	$4.59	16%
Per unit diluted	**$4.64**	$4.58	1%
Operating cash flow (1)	**83,326**	43,788	90%
Per unit basic	**$2.69**	$2.14	26%
Per unit diluted	**$2.34**	$2.13	10%
Net earnings (2)	**43,048**	11,365	279%
Per unit basic	**$1.32**	$0.55	140%
Per unit diluted	**$1.21**	$0.55	120%
Distributions declared	**68,713**	37,766	82%
Per unit	**$2.195**	$1.81	21%
Operating costs per boe	**$7.12**	$6.35	12%
Operating netbacks per boe	**$22.11**	$17.83	24%
Bank debt	**98,000**	88,000	11%
Units outstanding (000)			
End of period	**34,074**	22,942	49%
Weighted average - basic	**30,970**	20,470	51%
Weighted average - diluted	**35,641**	20,528	74%
Trading			
High ($)	**$12.67**	$11.19	13%
Low ($)	**$9.30**	$9.00	3%
Close ($)	**$12.54**	$9.79	28%
Average daily volume	**163,000**	68,700	137%
Operating			
Daily production (average)			
Oil (bbl)	**6,472**	5,307	22%
Gas (mcf)	**33,799**	18,488	83%
NGL (bbl)	**358**	144	149%
Total (boe) (3)	**12,463**	8,532	46%
Commodity prices			
Oil (per bbl)	**$34.46**	$33.66	2%
Gas (per mcf)	**$6.32**	$3.83	65%
NGL (per bbl)	**$31.82**	$25.15	27%
Average (boe) (3)	**$35.95**	$29.65	21%
Proved plus probable reserves (4)			
Oil & NGLs (mbbl)	**23,789**	20,608	15%
Gas (mmcf)	**99,197**	68,290	45%
Total (mboe)	**40,322**	31,989	26%
Drilling (gross wells)			
Gas	**80**	62	29%
Oil	**60**	40	50%
Coalbed methane	**19**	–	100%
Other	**5**	7	(29%)
Total	**164**	109	50%

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and accrued interest on convertible debentures.

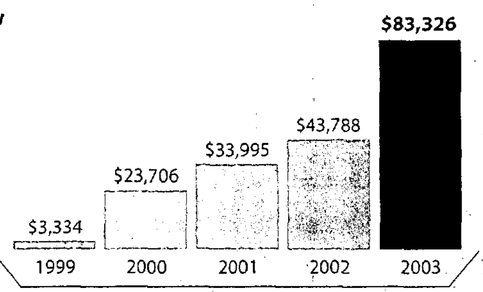
(2) Net income in the basic per trust unit calculation has been reduced by interest accrued on the convertible debentures.

(3) Boe's may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), 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.

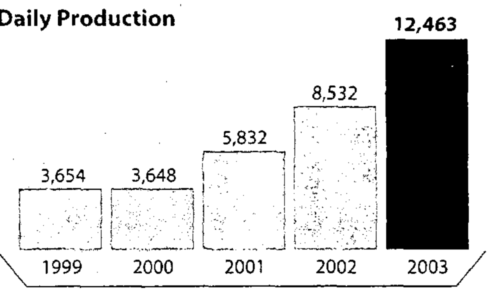
(4) 2002 reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

Key Performance Data

Cash Flow
(000)

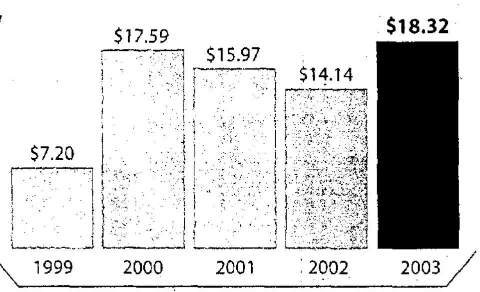


Average Daily Production
(boe)

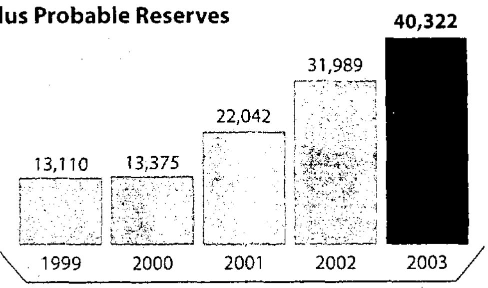


STRONG

Cash Flow
(per boe)

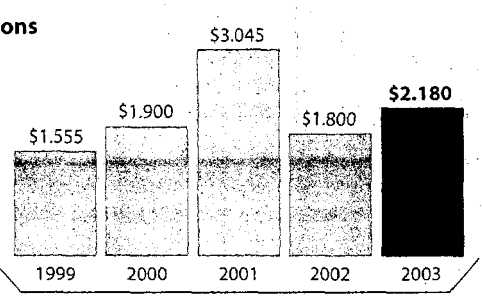


Proved Plus Probable Reserves
(mboe)

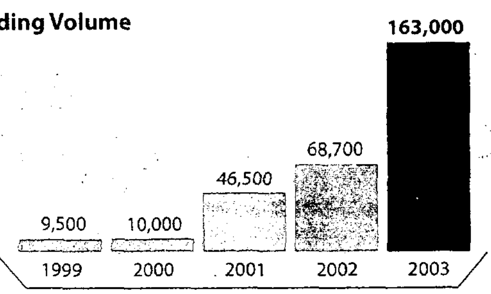


GROWTH

Distributions
(per unit)

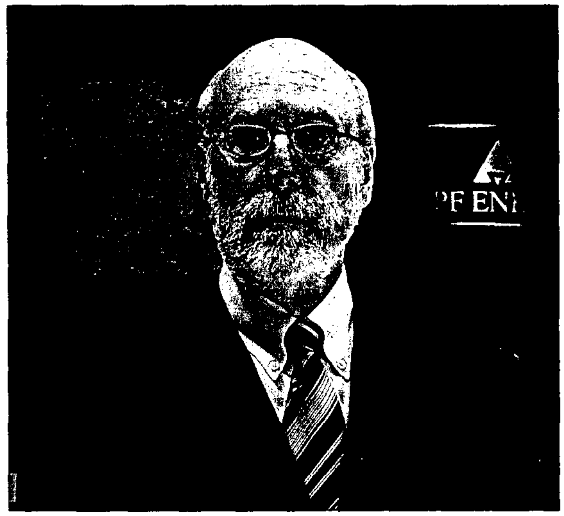


Daily Trading Volume



Message To Unitholders

Strong acquisitions, effective development and a buoyant commodity price environment drove APF to another successful year, with unitholders experiencing more than a 50% total return. Since inception, APF has delivered an average annual return of 22%, placing us among the industry leaders.



Martin Hislop
Chief Executive Officer

In last year's annual report, we remarked how the mergers and acquisitions market was shaping up to present a challenge for trusts that had been particularly effective at growing their businesses in recent years through the purchase of corporations and assets. That being said, APF had its most active year ever, executing on $167 million of transactions, adding further development potential to its inventory of drilling prospects. We strongly believe that we maintained our discipline of not over-paying for assets and look forward to harvesting the value from these new properties.

Interestingly, the challenge remains the same for 2004: finding assets and corporations that are not over-priced. With the impressive performance of the royalty trust sector over the last few years in a continued low interest rate environment, the group has flourished. But there has been a price for that popularity. A number of new names are now in the space competing for the same merger and acquisition opportunities. In 2003 alone, nine new trusts were created, bringing the total group to 26, considerably more than the 11 royalty trusts that were operating at the end of 2001. Compounding the challenge is that the historical raw material for acquisitions, being junior oil and gas companies, are trading at multiples even higher than many trusts. The management teams guiding these start-ups to such strong valuations, who had been successful in previous years selling their last ventures to the trusts, find themselves looking for an exit, but with fewer trusts willing to pay the price. Some will stay the course and diligently work their assets through the drill bit; some will be sold; and some will continue to grow through the cycle, either competing with the trusts for acquisitions or themselves converting into trusts.

In any event, the APF business plan is not to rely on the M&A function to maintain the stability of or our asset base, but to focus more on the drill bit as a value driver. During the four-year period from 2000 to 2003, APF replaced an average

1996

□ Completed $35 million IPO at $10 per unit in December and acquired initial properties for $21 million □ Year-end production was 1,700 boe/d.

1997

□ Executed first major transaction, the corporate purchase of Bayridge Resources, for $24 million only three months after IPO □ Acquired additional assets in core area of Countess.

1998

□ Raised $18 million of new equity in first financing since IPO □ With oil averaging $U.S. 14.42 per bbl on the year, APF identified a buying opportunity and acquired long-life light oil assets in the Central and Southern Alberta areas for a total of $27 million □ Despite low commodity prices, APF distributed $1.85 per unit □ Annual production averaged 3,673 boe/d.

of 106% of its production through drilling and optimization initiatives, perhaps the only trust to have done so.

While maintaining a reasonable risk profile, APF intends to be an even more active driller, which requires two things: human capital and opportunity.

Recognizing the need to generate internal prospects that have the potential to add greater value than acquisitions, APF has added key technical staff across all its core areas. Currently, the Trust has eleven geologists on staff complemented by three part-time geophysicists. On the operations and engineering side, APF has ten professionals. Both the geoscience and operations groups are supported by various office and field staff. Our technical team has been tasked with finding and creating value for APF unitholders however it might be found: by identifying upside as part of an acquisition; to optimizing existing production; to expanding known pools; to grass-roots initiatives that result in new discoveries.

APF's commitment to this effort and the extent to which opportunity has been provided is reflected in a variety of ways.

Firstly, all of the assets acquired by the Trust have come with upside potential. Some of that had already been recognized at the time of purchase and will be captured through development. This is the low-hanging fruit that is usually harvested within 12 to 18 months of an acquisition. But other layers of opportunities continue to be found and will be turned to account in the coming years. An example is APF's coalbed methane ("CBM") strategy, which was created through the corporate acquisition of CanScot Resources Ltd. in September, 2003. CBM has been a proven resource in the United States for many years and is now poised to make a significant impact on the western Canadian gas scene.

Steven Cloutier
President and Chief Operating Officer

With CanScot's technical team now part of APF, our Trust is uniquely positioned among its peers to take advantage of a potentially tremendous long-life resource that will be developed over a three to five year period.

Secondly, APF is becoming more active at the front end of the drilling equation, by increasing its land acquisition and seismic activity. While lower-risk development and infill drilling has been APF's bread and butter over the last few years, we felt strongly that we needed to expose ourselves to a more dynamic range of opportunities and the best way to accomplish that was through grass roots initiatives. APF's staff has been challenged to not only make the most of what it currently manages, but to find new areas for growth.

APF's 2004 capital budget has been set at approximately $40 million, with the potential to exceed that, should we identify new ideas that will add value. Funding will come from a variety of sources, the first of which will be cash flow.

1999

□ With an inventory of drilling prospects established, APF began to outline the development program that would result in four consecutive years of replacing at least 100% of production through drilling and optimization □ Without any significant acquisitions, APF's production remained steady at 3,654 boe/d.

2000

□ Completed new equity issue, raising $8.9 million to fund increased capital expenditure program □ Continued development of assets replaced 107% of annual production □ Asset swap at end of the year created new gas core area for APF at Redwater in Central Alberta □ Daily production averaged 3,648 boe.

2001

□ APF spent $115 million on acquisition and development initiatives, increasing production by 60% to 5,832 boe/d □ Corporate acquisition of Alliance Energy and follow-on purchase of Marathon Canada'a assets established strong platform for growth in Southeast Saskatchewan □ A total of $66 million was raised in two public financings □ Annual distributions amounted to a record $3.04 per unit.

Since completing its IPO, APF has been among the industry leaders in withholding a portion of cash flow to provide capital for drilling, development and optimization. In aggregate since inception, APF has paid out 85% of cash flow. Going forward, we're targeting a payout range of 80% to 90% for the year. The payout ratio may vary from month to month, but we are nonetheless committed to withholding a meaningful portion of cash flow.

The second source is APF's recently launched Premium Distribution Reinvestment Plan ("DRIP"). With a 40% participation rate, the DRIP will contribute significantly to the capital program, with $2.5 to $3.0 million of equity being issued each month.

APF's internal estimates indicate that the results of the capital program will maintain a stable production profile through 2004.

In conjunction with our development and optimization initiatives, we will continue to identify and evaluate potential acquisitions. While our target range would be transactions between $25 and $50 million, we have the resources and access to capital that would allow us to execute on an opportunity as large as $350 million. But as we have stated in the past: we are determined to execute on acquisitions only if the right opportunity materializes.

We want to thank our employees, consultants and contractors for all of their hard work during 2003, and our Board of Directors for their guidance.

M Hislop

Martin Hislop
Chief Executive Officer

S Cloutier

Steven Cloutier
President and Chief Operating Officer

February 20, 2004
Calgary, Alberta

2002

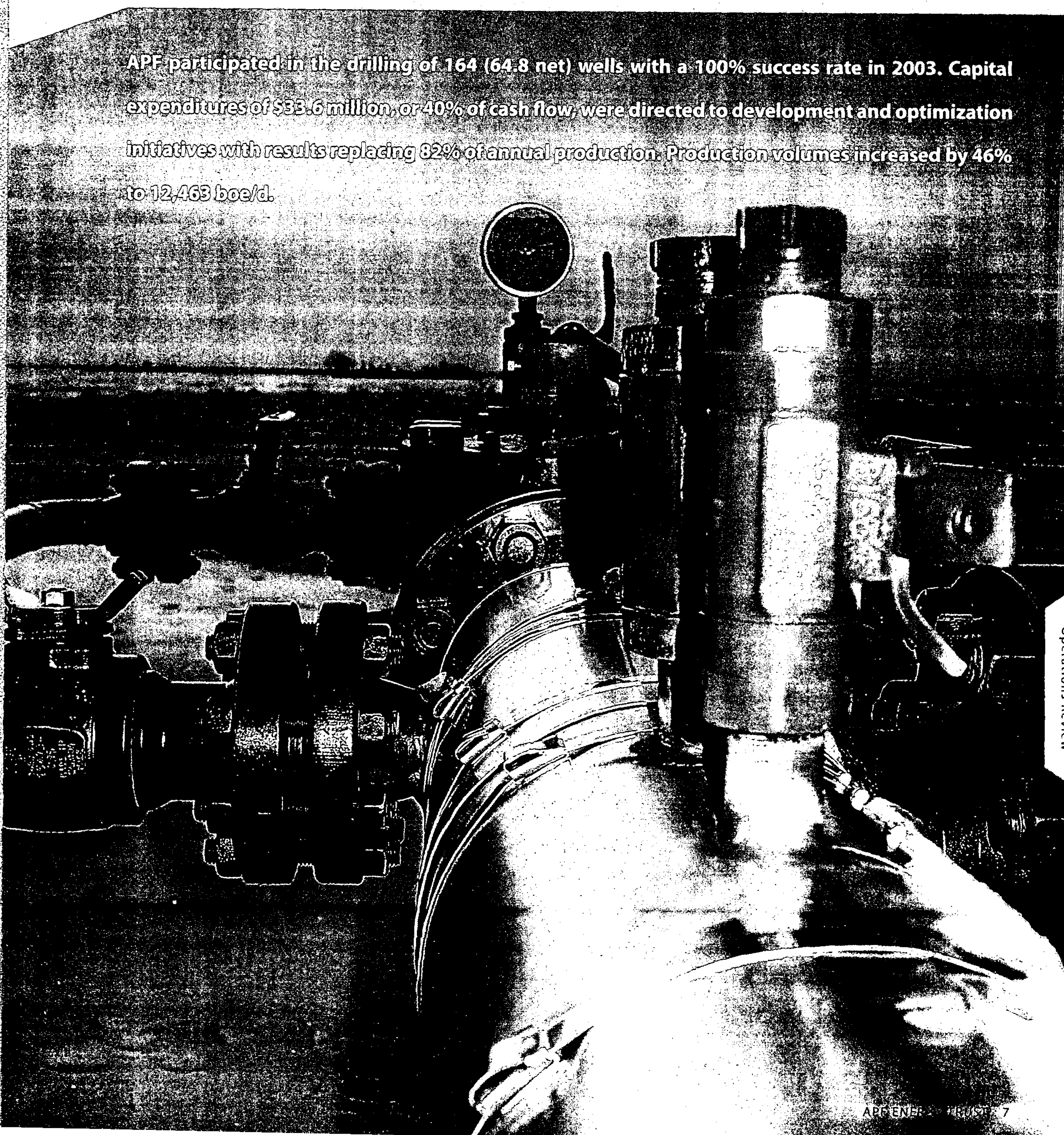
□ APF strengthened its presence in Southeast Saskatchewan with the purchase of Kinwest Resources and its joint venture partner for $59.5 million □ Acquired assets at Paddle River, Alberta for $22.7 million, expanding APF's gas operations in Central Alberta □ Daily production averaged 8,532 boe.

2003

□ APF completed three corporate and several asset acquisitions for a total of $167 million, increasing the production base in Southern and Central Alberta □ The Trust established a coalbed methane group through the purchase of CanScot Resources □ Raised more than $100 million in new equity and issued a $50 million convertible debenture □ Management internalized □ Daily production averaged 12,463 boe and unitholders enjoyed a 50% total return.

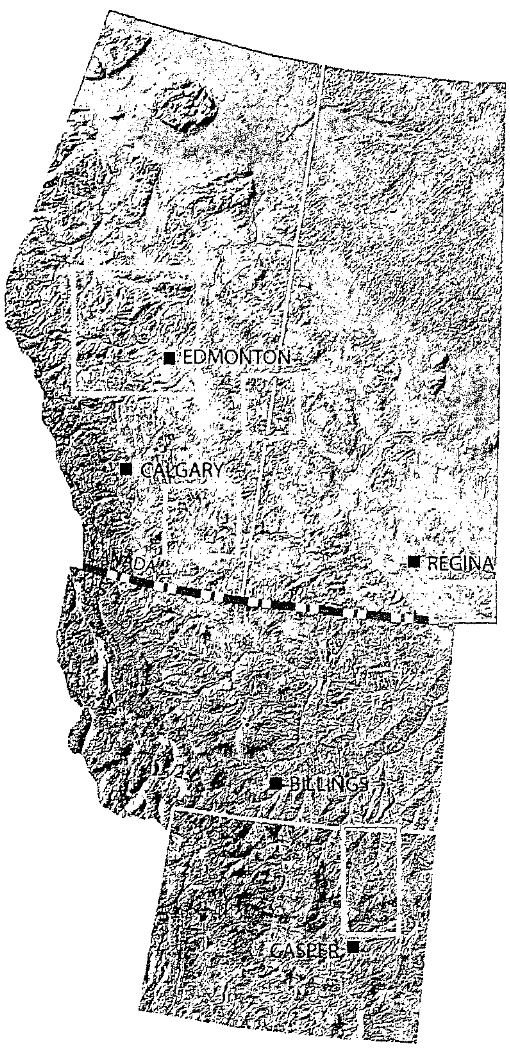
Operations Review

APF participated in the drilling of 164 (64.8 net) wells with a 100% success rate in 2003. Capital expenditures of $33.6 million, or 40% of cash flow, were directed to development and optimization initiatives with results replacing 82% of annual production. Production volumes increased by 46% to 12,463 boe/d.



Development and Optimization

Left to right: Dan Allan, VP Coalbed Methane; Bonnie Nicol, VP Operations; John Ewing, VP GeoScience; Ken Pretty, VP Corporate Development and Land



Taking advantage of an opportunity-rich inventory of drilling prospects and a technical team deep in experience, APF's development and optimization program reached record levels during 2003. In total, the Trust participated in 164 (64.8 net) wells with a 100% success rate. Capital expenditures in 2003, excluding acquisitions, totalled $33.6 million and resulted in proved plus probable reserves additions of 3,720 mboe, replacing 82% of APF's 2003 annual production, as the drill bit continued to maintain the stability of the APF asset base. Over the past four years, APF has replaced an average of 106% of annual production through development initiatives, one of the strongest reserve replacement track records in the sector.

APF's operations are divided into five Business Units: Southern Alberta; Central Alberta; East Alberta/Heavy Oil; Southeast Saskatchewan; and Coalbed Methane. Each Business Unit is comprised of technical and business professionals and support staff whose mandate is to increase the value of the assets under their management through a combination of development, exploration, optimization and acquisitions.

SOUTHERN ALBERTA

The Southern Alberta Business Unit is responsible for two general areas, most of which is operated: the Countess property, which APF acquired as part of its initial public offering in 1996; and the assets acquired on the takeover of Nycan Energy in April, 2003. This area is prospective for shallow gas in many horizons, including the Belly River, Milk River, Medicine Hat and Second White Specks formations. APF also holds deeper rights on a number of its properties.

Fourth quarter production in the Southern Alberta Business Unit was comprised of 15 mmcf/d of gas and 440 bbl/d of oil and natural gas liquids.

Drilling at Countess was extensive in 2003, with development initiatives replacing 100% of production on a proved plus probable basis. In total, APF drilled 38 (28.2 net) gas wells, predominantly in the Milk River and Medicine Hat zones.

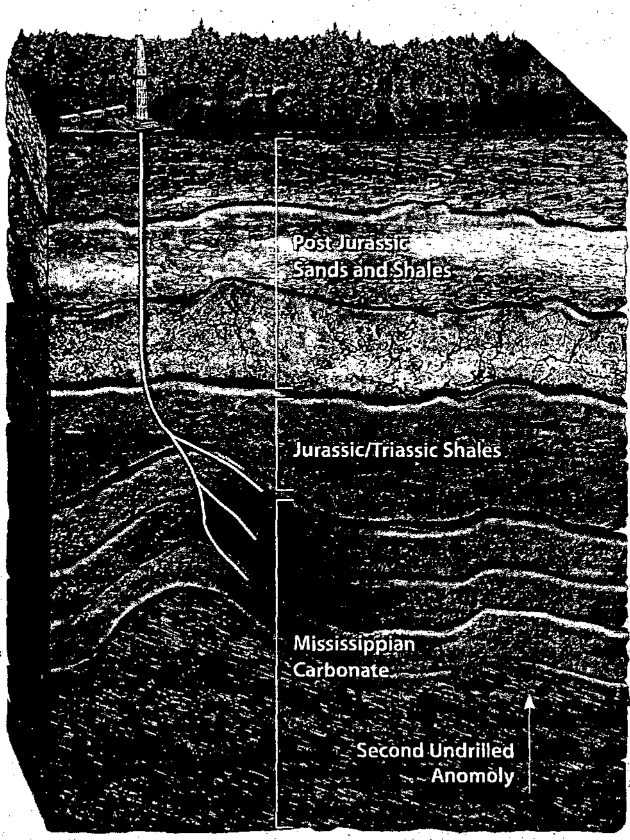
The corporate acquisition of Nycan brought a large suite of contiguous multi-zone assets located southwest of the Countess field. During 2003, APF participated in seven (1.7 net) wells on the Nycan lands.

The 2004 budget contemplates total capital expenditures in the Southern Alberta Business Unit of $8 million, with 54 gross wells targeting a variety of shallow and deeper horizons.

Mike Davies

Jiun (Shig) Shigematsu

The multi-zone potential of APF's Southeast Saskatchewan properties



Note: Not to scale

EAST ALBERTA AND HEAVY OIL

The Hawk Oil acquisition in February, 2003 provided APF with a new heavy oil platform along the Alberta/Saskatchewan border. During the year, the Trust drilled seven wells into a new pool at South Epping, which is now being considered for waterflood.

Total production from this Business Unit averaged 2,147 boe/d during the fourth quarter of 2003, with heavy oil accounting for 1,300 bbl/d, or 10% of the total APF portfolio. With high oil prices and a reasonable differential from light quality crude, APF views its heavy oil assets as providing solid cash flow with upside potential.

Total capital expenditures for the East Alberta/Heavy Oil Business Unit are expected to amount to $1.4 million in 2004, covering the drilling of five wells.

CENTRAL ALBERTA

Central Alberta has been an active area for APF, as acquisitions and development initiatives pushed fourth quarter average production to 3,700 boe/d, comprised of 14 mmcf of gas and 1,370 bbl of oil and NGLs. With tremendous multizone potential, this area will continue to play an important role in APF's development and optimization strategy.

Total capital expenditures in 2003 amounted to $8.6 million, as the Trust participated in 48 (9.8 net) wells in areas such as Paddle River, Leaman, Pembina and Redwater.

For 2004, the APF budget contemplates $9.2 million of capital to be spent on seismic, land acquisition and the drilling of 25 gross wells.

Alison Banda

Rick James

SOUTHEAST SASKATCHEWAN

APF's largest oil producing area is Southeast Saskatchewan, where light gravity crude is produced predominantly from the Frobisher, Midale and Alida formations. Since acquiring its initial interests in the area in 2001, APF has been very effective in executing both corporate development initiatives as well as its drilling strategies. In particular, the use of 3D seismic to delineate opportunities in under-exploited pools has proven very successful.

2003 capital expenditures of $11.1 million resulted in 16 gross (9.1 net) horizontal oil wells and one vertical stratigraphic test. At Queensdale, APF drilled four (2.4 net) horizontal wells and replaced 260% of production. During the year, APF acquired minor partner interests and one quarter section of land, offsetting APF operated production. The acquisition set up five (4.8 net) horizontal locations which have been included in the 2004 drilling program.

Fourth quarter 2003 production averaged 4,100 boe/d, of which 96% was oil. In addition to Queensdale, active production and development areas in this Business Unit include Tatagwa and Macoun.

For 2004, a budget of $14.1 million has been allocated to the drilling of 20 gross wells.

Drilling Activity

Years Ended December 31	**2003**		2002		2001		2000	
	Gross	**Net**	Gross	Net	Gross	Net	Gross	Net
Oil	**60**	**19.4**	40	12.0	40	8.9	33	3.2
Gas	**80**	**40.2**	62	33.0	33	31.3	65	14.8
CBM	**19**	**4.4**	–	–	–	–	–	–
Other	**5**	**0.8**	7	1.7	1	0.1	27	0.5
Dry and abandoned	**–**	**–**	–	–	2	2.0	–	–
Total	**164**	**64.8**	109	46.7	76	42.2	125	18.5
Success rate		**100%**		100%		95%		100%

Capital Expenditures

Years Ended December 31 ($000)	**2003**	2002	2001	2000	1999
Corporate and asset acquisitions	**164,550**	90,101	105,717	13,249	3,895
Land acquisitions	**2,310**	616	239	147	143
Seismic	**1,070**	497	208	15	99
Drilling and completion	**24,287**	15,890	12,490	3,912	2,232
Production facilities	**7,749**	3,684	3,340	1,619	950
Other	**494**	908	(52)	–	5
Subtotal	**200,460**	111,696	121,942	18,942	7,324
Dispositions (including swaps)	**(9,284)**	(10,569)	(6,903)	(12,393)	(2,326)
Net capital expenditures	**191,176**	101,127	115,039	6,549	4,998

Efficiency of the Capital Program

Finding and Development Costs ("F&D")(1)

Proved plus probable (3)

($000)

	2003	2002	2001
Total F&D	**$ 33,601**	$ 21,595	$ 16,225
Change in future development	**$ 27,875**	$ 11,525	$ 5,625
Total	**$ 61,476**	$ 33,120	$ 21,850
Net reserve additions (mboe)(2)	**3,002**	4,054	2,690
($/boe except recycle ratio values)(2)			
F&D cost	**$ 20.48**	$ 8.17	$ 8.12
Operating netback	**$ 22.11**	$ 17.83	$ 20.42
Recycle ratio	**1.08**	2.18	2.51
Rolling three year average F&D cost	**$ 11.95**	$ 7.88	$ 9.49
Rolling three year average Netback	**$ 20.12**	$ 19.84	$ 17.27
Rolling three year average recycle ratio	**1.68**	2.52	1.82

Finding, Development and Acquisition Costs ("FD&A")(1)

Proved plus probable (3)

($000)

	2003	2002	2001
Total FD&A	**$ 33,601**	$ 21,595	$ 16,225
Change in future development	**$ 27,875**	$ 11,525	$ 5,625
Net acquisitions	**$ 157,576**	$ 79,532	$ 98,814
Total	**$ 219,052**	$ 112,652	$ 120,664
Net reserve additions (mboe)(2)	**12,881**	13,064	10,740
($/boe except recycle ratio values)(2)			
FD&A cost	**$ 17.02**	$ 8.62	$ 11.24
Operating netback	**$ 22.11**	$ 17.83	$ 20.42
Recycle ratio	**1.30**	2.07	1.82
Rolling three year average FD&A cost	**$ 12.33**	$ 9.59	$ 11.66
Rolling three year average Netback	**$ 20.12**	$ 19.84	$ 17.27
Rolling three year average recycle ratio	**1.63**	2.07	1.48

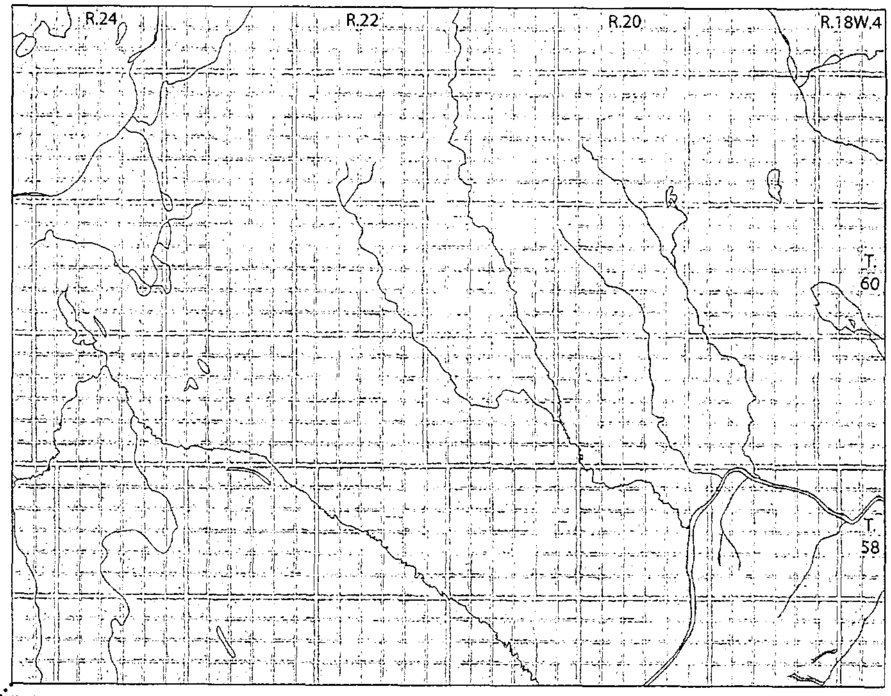
(1) The aggregate of the exploration and development costs incurrred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(2) Boe's may be misleading, particularly if used in isolation. In accordance with NI 51-101, 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.

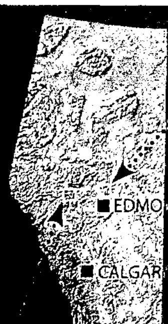
(3) Reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties for 2002 and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

Redwater

Product		Sweet natural gas
Year acquired		2000
Net undeveloped acres		36,305
Working interest		53%
P+P reserves (mboe)		1,508
Average 2003 boe/d		855
2003 drilling	Gross	Net
Oil	0	0.0
Gas	6	6.0
Total	6	6.0
2003 CapEx		$4.7 million

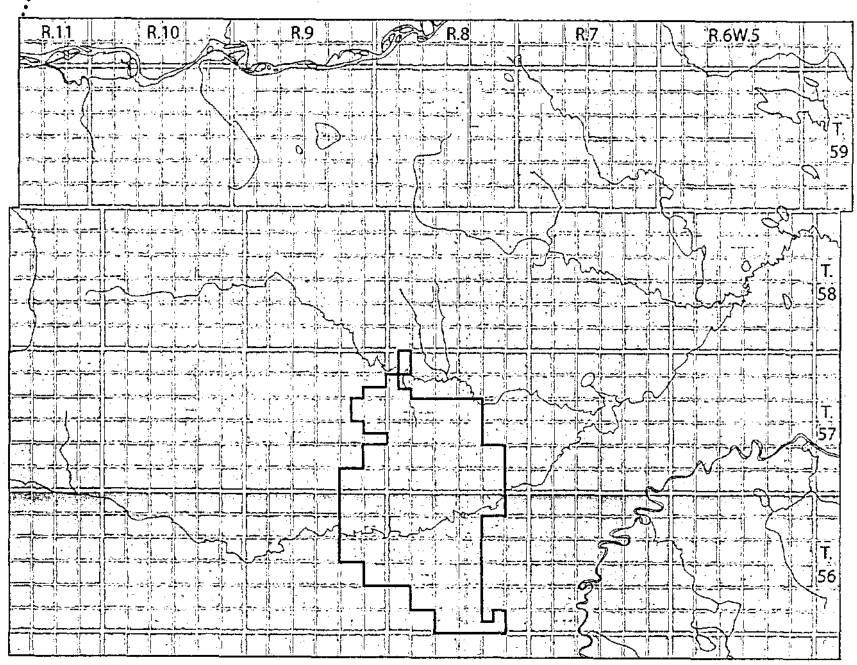


APF Land



Central Alberta

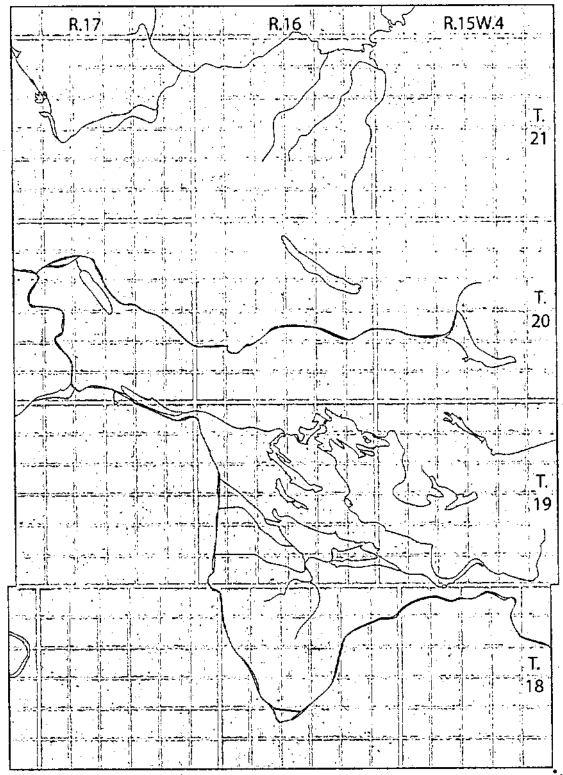
APF assets located in the Central Alberta region have multi-zone potential in wells being drilled to depths of 200 to 1,700 metres. APF utilizes seismic data to define the structural and stratigraphic traps. Assets in this area are currently being exploited for their gas production with key horizons at the Cretaceous Mannville and Jurassic Nordegg formations.



APF Land — Paddle River Gas Unit

Paddle River

Product		Natural gas and oil
Year acquired		2002
Net undeveloped acres		25,888
Working interest		61%
P+P reserves (mboe)		1,240
Average 2003 boe/d		827
2003 drilling	Gross	Net
Oil	3	0.6
Gas	1	0.5
Total	4	1.1
2003 CapEx		$2.9 million



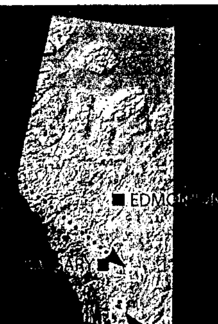
APF Land

Countess

Product		Sweet natural gas
Year acquired		1996-97
Net undeveloped acres		405
Working interest		87%
P+P reserves (mboe)		5,893
Average 2003 boe/d		1,720
2003 drilling	Gross	Net)
Oil	0	0.0
Gas	38	28.2
Total	38	28.2
2003 CapEx		$7.8 million

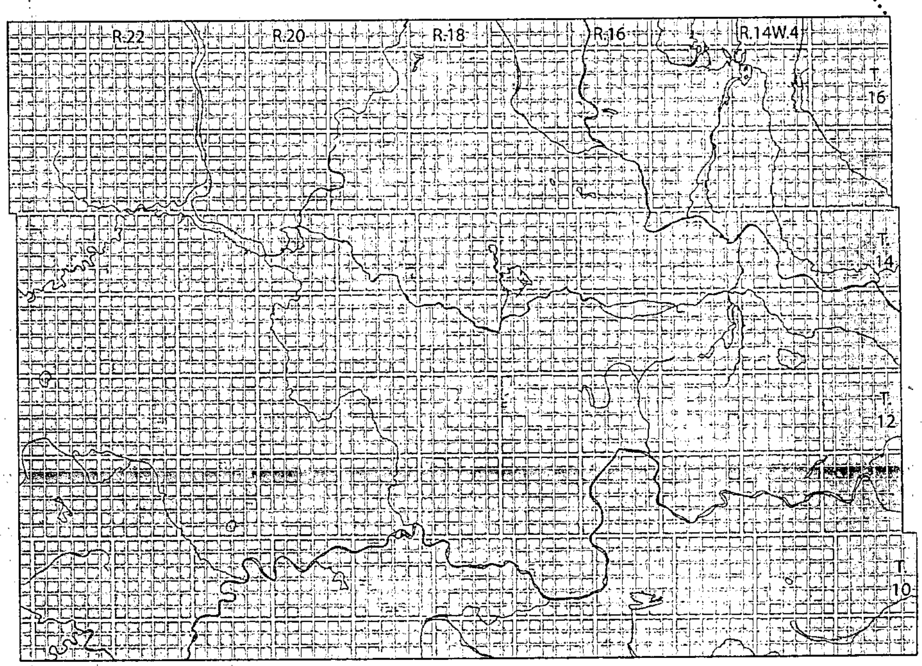
Southern Alberta

The Southern Alberta region is characterized by predominately shallow gas production. The primary producing zones include the Milk River, Medicine Hat and Second White Specks formations. The 2003 acquisition of Nycan also increased APF's exposure to Mannville oil and gas production.

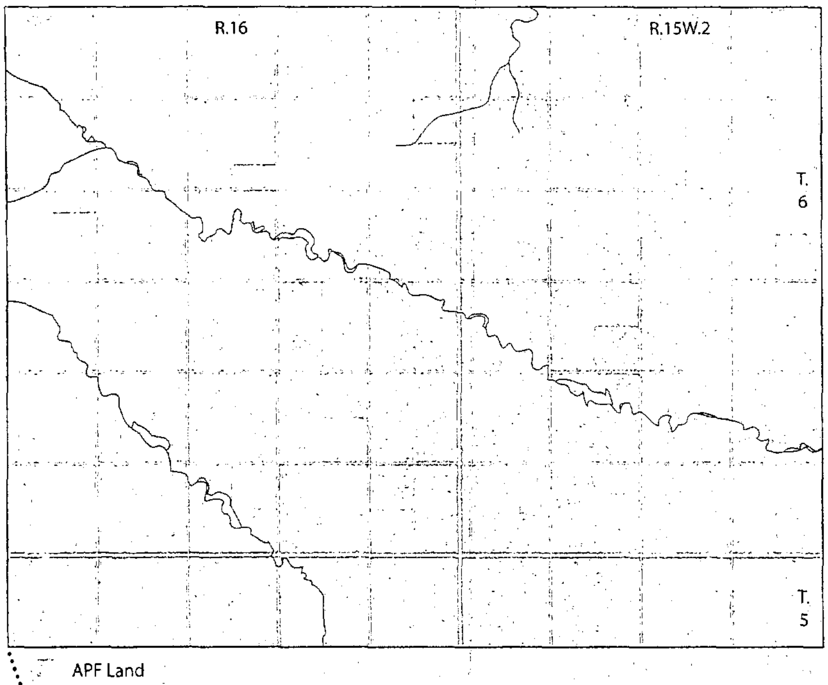


Turin/Retlaw

Product		Natural gas and oil
Year acquired		2003
Net undeveloped acres		49,451
Working interest		46%
P+P reserves (mboe)		1,673
Average 2003 boe/d		504
2003 drilling	Gross	Net
Oil	1	0.0
Gas	6	1.7
Total	7	1.7
2003 CapEx		$1.8 million



APF Land



Tatagwa

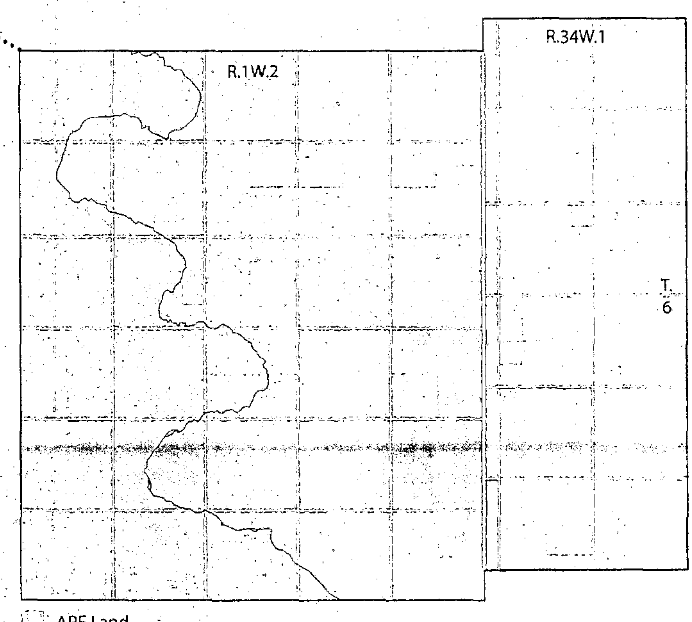
Product		Medium oil
Year acquired		2001
Net undeveloped acres		2,508
Working interest		57%
P+P reserves (mboe)		2,159
Average 2003 boe/d		838
2003 drilling	Gross	Net
Oil	4	2.9
Gas	0	0.0
Total	4	2.9
2003 CapEx		$2.52 million

Southeast Saskatchewan

Light oil production in this region is primarily from Mississippian carbonate reservoirs. The key productive horizons are the Alida and Midale beds. Extensive use of 3D seismic combined with horizontal drilling technology is utilized to optimize assets in this region.

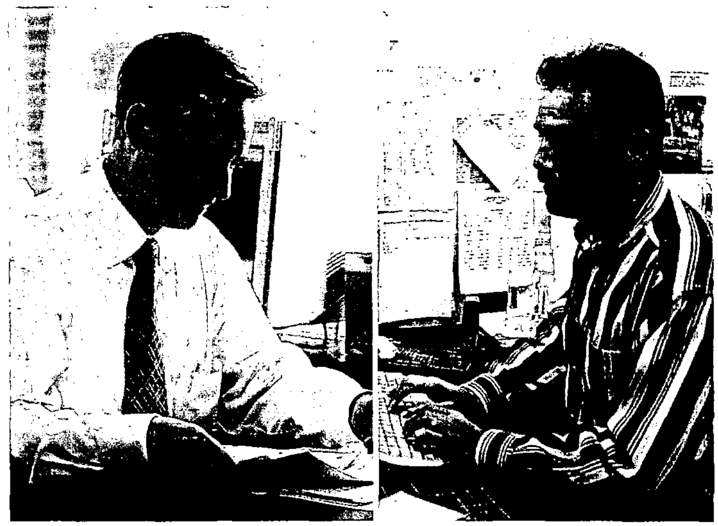
Queensdale

Product		Light oil
Year acquired		2001
Net undeveloped acres		12,315
Working interest		50%
P+P reserves (mboe)		2,143
Average 2003 boe/d		975
2003 drilling	Gross	Net
Oil	5	3.0
Gas	0	0.0
Total	5	3.0
2003 CapEx		$2.70 million



Coalbed Methane

In September, 2003, APF completed the acquisition of CanScot Resources Ltd., a Calgary-based oil and gas company with coalbed methane ("CBM") operations in Alberta and Wyoming. The CanScot acquisition provided APF with an entry into the CBM business and created a platform from which to execute this exciting new strategy.



Jeff Shaw *Mark Livingstone*

WHAT IS CBM?

CBM is natural gas produced from coal seams. This is accomplished through a reduction of reservoir pressure within the coal and is normally achieved by pumping out water. In a coal seam, natural gas is bound to the coal by molecular forces. When the pressure is released through dewatering, gas is liberated. The structure of the coals allows them to hold approximately six times the volume that can be held in a conventional reservoir.

THE OPPORTUNITY

The development of CBM is in its infancy in Canada. It is a very important energy source in the U.S. where current production accounts for close to 10% of domestic natural gas production. As the Western Canadian Sedimentary Basin rapidly matures, the need to replace production with unconventional supply is creating new opportunities. The development of CBM in particular will be a critical factor in allowing Canada to maintain current rates of natural gas production.

The estimates for Canadian CBM reserves are substantial. The Geological Survey of Canada believes there is between 180 tcf and 550 tcf of gas in place within the country's coals. Of equal importance, the Alberta Plains, the largest geographic area for CBM potential, are estimated to contain between 115 tcf and 350 tcf of gas in place. For perspective, the volume of undiscovered conventional gas in place is estimated at approximately 250 tcf, thus making CBM a critical resource for the future energy development of the country.

OUR EXPERTISE

With the acquisition of CanScot, APF established itself as a producer and developer of CBM, both in Canada and the United States. APF's CBM team has been actively involved in the development of numerous projects in the Powder River Basin of Northeast Wyoming and has established commercial production from several fields. The Powder River Basin is the most active U.S. CBM area and the results have been impressive. From an average of 6,000 mcf/d in 1994, CBM production has increased exponentially to a basin average of over 900 mmcf/d in 2003. This explosive growth has demonstrated the significant economic impact of CBM. APF believes that the experience acquired from these operations will be extremely valuable as the Trust begins to develop its CBM projects in Western Canada.

COALBED METHANE IN A ROYALTY TRUST PORTFOLIO

Several attributes of CBM reserves and production are well suited to an energy trust. Coal seams hold significantly more gas per unit area than conventional reservoirs, resulting in a longer reserve life. In addition, because coal seams often require a lengthy de-watering period, the typical CBM decline curve is more attractive than that of a conventional reservoir as CBM has a more gradual production decline.

Finally, and of equal importance, full scale CBM development is generally low risk. Once the higher risk initial pilot project has been determined to be commercial, the exposure associated with full scale development becomes relatively low. The ability to have a large number of low risk development locations makes CBM development attractive in a royalty trust portfolio.

POWDER RIVER BASIN

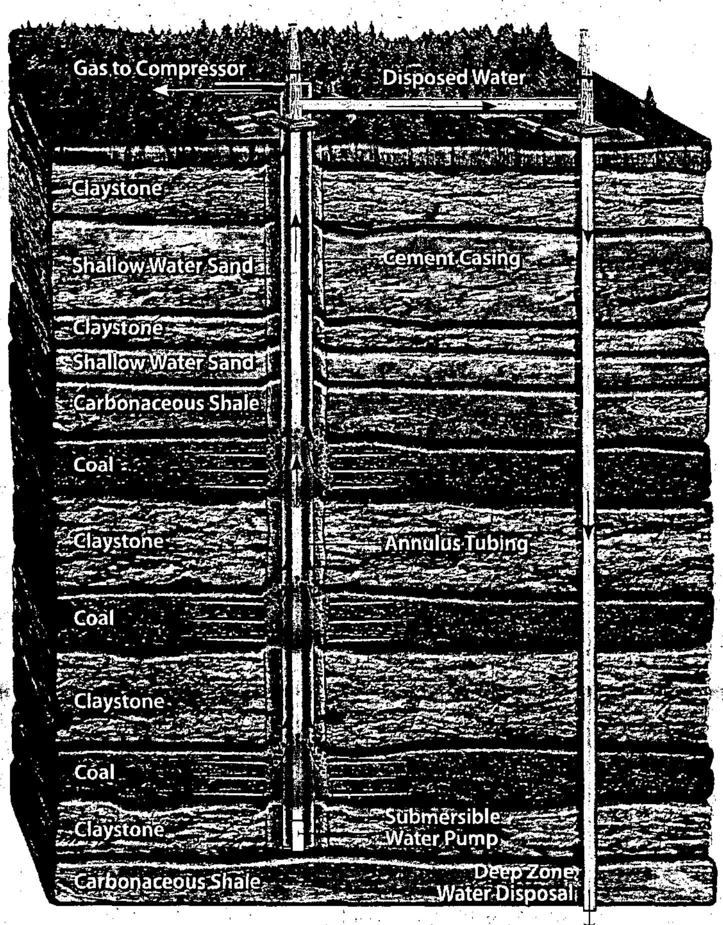
APF is currently active in six CBM projects in the Powder River Basin. Three of these fields are currently developed and producing gas. The remaining three projects are in the initial stages of development. The average cost to drill, case and complete a well in this area is approximately $U.S. 75,000.

Hensley Draw

Thirty CBM wells have been drilled to date in this area, where APF has an average 23% working interest. These wells are completed in the Cook coal, which averages 11 metres in thickness at a depth of approximately 152 metres. Due to water discharge limitations, only 23 wells are currently on production. Gross production peaked at approximately 3,400 mcf/d, during the first quarter of 2003 and has now declined to approximately 2,000 mcf/d. An additional ten development locations are planned for drilling this year.

Kane

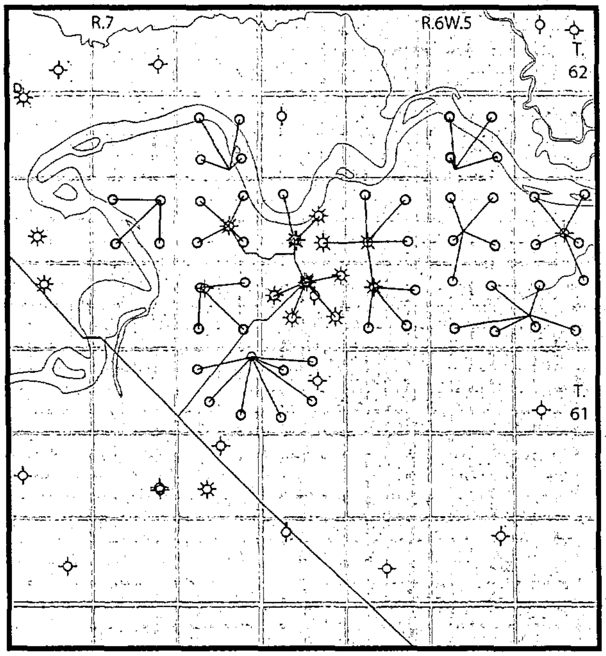
Fourteen CBM wells were drilled in late 2003 and are currently on production. These wells have been dually completed in both the Upper and Lower Wyodak coals, which average 11 metres in thickness per coal, at a depth of approximately 122 metres. As a result of the close proximity of adjacent production, many of these wells began producing gas immediately with a limited period of de-watering. Gross production is currently at 1,400 mcf/d and continues to increase as the coals are de-watered. An additional 30 locations have been identified for development over the next 18 months. APF's interests range from 16% to 25%.



Typical Alberta Coalbed Methane Well

Typical Upper Mannville CBM completion with multi-seam perforations and associated water disposal well into Devonian Wabamun formation

Note: Not to scale



APF Land — Natural Gas Pipeline

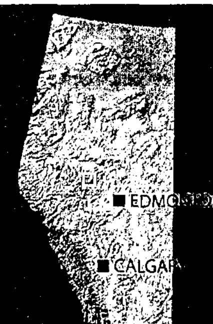
Corbett Creek

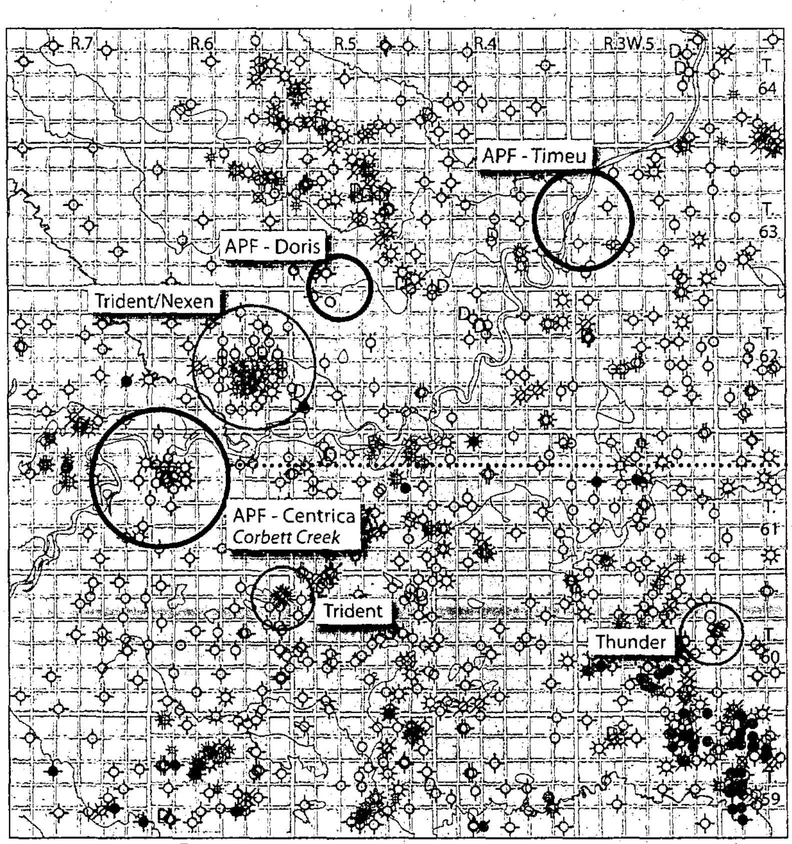
- ☼ Phase 1: 4 wells, 1 water disposal well
- ☼ Phase 2: 6 wells
- ○ Phase 3: potential locations

Phase 1 was completed in 2003 and Phase 2 was completed in the first quarter of 2004. Phase 3 represents the full commercial potential for this area.

Corbett

The target coals occur within the Upper Mannville formation at a depth of approximately 1,000 metres and total coal thickness varies from six to eight metres in four separate coal seams. The two thickest coal seams have been targeted for exploitation.





APF Land — APF Pilot Project — Pilot Project

Greater Corbett Area

Product	Coalbed methane	
Year acquired		2003
Net undeveloped acres		28,861
Working interest		66%
2003 drilling	Gross	Net
Coalbed methane	2	0.5
Total	2	0.5
2003 CapEx		$1.2 million

K-Bar

Twenty CBM wells have been drilled and are on production. Ten of these wells were completed in the Big George coal, which averages 12 metres in thickness at a depth of approximately 185 metres. Gross gas production peaked at over 3,000 mcf/d during the second half of 2002 after twelve months of de-watering. Production volumes have slowly declined to current rates of approximately 2,000 mcf/d. APF has an average 16% working interest in this area. The remaining ten wells were completed in the Wyodak coal, which averages eight metres in thickness at a depth of 244 metres. This lower coal is exhibiting increasing gas production as the coals continue to be de-watered.

North Carson

This area is slated for development in 2004. With an 18% to 25% interest, an initial pilot project of eight wells is anticipated to be drilled by the end of the third quarter. These wells are planned to be drilled for co-mingled production in the Cook and Canyon coal seams, which average 7.6 metres in thickness at a depth of approximately 168 metres. A second round of drilling is planned on the same locations for co-mingled production from the Wall and Pawnee coal seams. Over 60 additional locations have been identified for drilling within the next 24 months.

Big Bend

APF has the largest interest at 70% and is manager of this significant CBM project. Within the last few months, two test wells have been drilled to confirm gas content, structure and coal thickness. Based upon these results, an additional six wells will be drilled by the end of the second quarter. The initial eight well pilot project should begin de-watering during the third quarter of 2004. A second phase of 18 wells is planned for late 2004. Full scale development anticipates over 90 CBM wells on this project by late 2005.

Coal Gulch

This project area is slated for an initial development of 16 wells in 2005. These wells will target the Big George coal, which is approximately 15 metres thick at a depth of close to 670 metres. Several pilot projects in the Big George coal, located to the east of this project area have demonstrated excellent results.

ALBERTA COALBED METHANE

Based on an independent analysis of the potential CBM targets within the Western Canadian Sedimentary Basin, various prospective coal units have been identified and quantified. The greatest prospectivity occurs within the Upper Mannville, which is estimated to contain approximately 65% of the potential gas in place within the Alberta Plains. Several discrete areas have been targeted for land acquisition and subsequent evaluation. APF has focused its attention on an area approximately 113 kilometres northwest of Edmonton where three CBM project areas have been assembled. No reserves have been assigned for APF's Alberta CBM properties, as NI 51-101 requirements specify that reserves cannot be booked until commercial production levels are established.

Corbett Creek

Following the drilling, coring and testing of an initial exploratory well, four CBM wells and a water disposal well were drilled in late 2002 with water production commencing in the spring of 2003. Following nine months of de-watering an additional six wells were drilled and completed in early 2004 with production commencing in March. It is anticipated that by accelerating water production, the associated gas production will increase. Based on the calculated permeability of the coal it is estimated that de-watering will take a minimum of 12 months. Once commercial rates are achieved, full scale development is expected to commence. Each well costs approximately $600,000 to drill, case and complete. APF has an average 42% interest in over 10,000 acres at Corbett Creek with the potential to drill approximately 68 CBM wells.

Doris

At Doris, APF has assembled 22,400 gross acres of contiguous lands with interests between 35 and 50%. An initial exploratory test well was drilled in 2003 to evaluate the coals and encountered several conventional gas zones and was completed in those intervals and placed on production. A second well on this CBM prospect was also successful in finding conventional gas and was placed on production in early 2004. A third well has now been drilled and tested the Upper Mannville coals and has confirmed the potential for

Peter Klein

Elizabeth Palma

Violetta Piekarska

CBM, with an initial five well pilot project planned for late 2004. An existing CBM project is currently underway by another operator approximately three miles to the west where over 40 wells have been drilled, mostly in the last year. Extensive de-watering is in progress on that property, which APF believes will assist in the regional de-pressuring of the coals.

Timeu

An initial exploratory test well was drilled in the first quarter of 2004 and cored the Upper Mannville coal section. Following a thorough review of the data, a decision will be made regarding the drilling of a five well pilot project. APF has assembled over 5,700 acres of land on this project, and has a 100% working interest in the area.

Trochu-Rowley

APF has several active projects underway in this area located northeast of Calgary where over 60 CBM wells have been drilled by several companies. In this region, CBM development targets the Horseshoe Canyon coals. These coals are relatively thin and developed in up to ten individual seams with a total aggregate thickness of six to ten metres. These coals are also very shallow at depths of approximately 250 metres. These wells cost approximately $250,000 to drill, case and complete. One attribute of these coals is that there is no initial water production. APF is drilling, completing and immediately placing these CBM wells on production. Due to the extremely competitive nature of this development, the Trust has established several joint ventures in this area and hopes to expand its operations here over the next 12 months.

ENVIRONMENTAL ISSUES

In Alberta, all oil and gas operations are conducted under the rules and regulations of the Alberta government. All activities pertaining to the handling and disposal of produced CBM water are fully compliant with existing regulations from the Energy and Utilities Board and the Department of Energy. Produced CBM water is disposed into the subsurface in approved water disposal zones.

In Wyoming, the Wyoming Oil and Gas Conservation Commission, the Bureau of Land Management and the Department of Environmental Quality are responsible for regulation of the oil and gas industry. Produced CBM water is either disposed of in approved drainage areas or in applicable water containment reservoirs, with full consultation and approval of surface landowners.

APF is committed to ensuring that all its operations are conducted in an environmentally responsible manner, taking into consideration the sensitivity of surrounding areas and the impact on all stakeholders.

Oil and Natural Gas Reserves

All of APF's Canadian reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ"), while coalbed methane ("CBM") reserves in the United States were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"). Both reports were prepared effective January 1, 2004. All reserves were evaluated in accordance with the new standard, NI 51-101. No reserves were assigned to APF's Alberta CBM assets.

NI 51-101 replaced the former National Policy 2-B ("NP 2-B"). Under the new instrument, the total proved reserves are to reflect a 90% confidence level; that is, nine times out of ten, actual reserves recovered should exceed the estimated proved reserves. The proved plus probable reserves are to reflect a 50% or greater confidence level and are effectively meant to be the "best estimate" of the Company's reserves. This compares to the previous definition of "likelihood of existence" under NP 2-B. The following reserves summary has been prepared comparing the new proved plus probable reserves to previous proved plus risk adjusted (50%) probable reserves, which were commonly referenced as "established reserves" under NP 2-B.

The following table summarizes the Company Interest Reserves assigned in the GLJ and McDaniel reports. Company Interest Reserves are defined as working interest reserves (before the deduction of royalties) plus royalty interest reserves.

Summary of Reserves As at December 31, 2003	Natural Gas (mmcf)	Light & Medium Oil (mbbl)	Heavy Oil (mbbl)	NGL's (mbbl)	Total (mboe) (2)
Proved					
Developed producing	65,796	11,899	969	818	24,652
Developed non-producing	4,882	838	624	86	2,361
Undeveloped	2,016	2,269	201	75	2,880
Total Proved	72,695	15,006	1,793	979	29,894
Probable	26,503	4,629	1,210	172	10,428
Proved + Probable (1)	99,197	19,634	3,003	1,151	40,322

Columns may not add due to rounding

APF's reserves were evaluated using the GLJ January 1, 2004 price forecast. The net present values shown below do not necessarily represent the fair market value of the reserves.

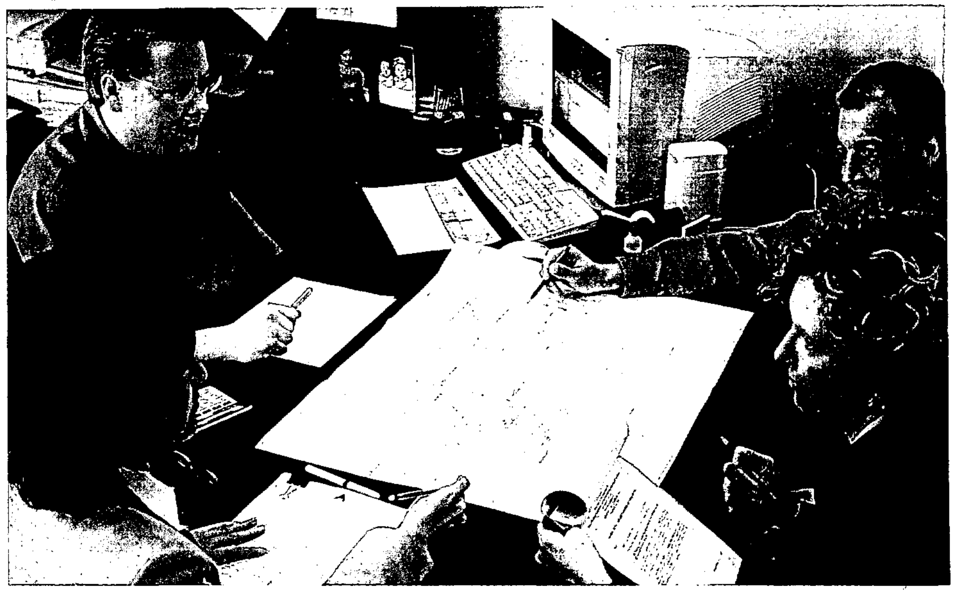
Net Present Value Of Future Net Revenue Before Income Taxes (Based on forecast pricing and costs)
As at December 31, 2003

	Present Value Discounted				
Reserve Category ($millions)	0%	8%	10%	12%	15%
Proved					
Developed producing	321.8	242.4	229.3	217.9	203.2
Developed non-producing	35.1	17.3	15.5	14.1	12.5
Undeveloped	31.7	14.6	12.2	10.3	8.0
Total Proved	388.6	274.3	257.0	242.3	223.7
Probable	123.8	66.8	59.4	53.4	46.0
Proved + Probable (1)	512.4	341.0	316.5	295.6	269.7

Columns may not add due to rounding

(1) Reserve numbers for 2002 and 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

(2) Boe's may be misleading, particularly if used in isolation. In accordance with NI 51-101, 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.



Clockwise from top left: Murray Heather, Kevan Newman, Pat Forrest, Dilia Wu

GLJ Forecast at January 1, 2004 Year	Foreign Exchange ($U.S./$Cdn.)	WTI Oil ($U.S./bbl)	Heavy Oil ($Cdn./bbl)	Edmonton Light Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2004	0.75	29.00	20.25	37.75	5.85
2005	0.75	26.00	20.25	33.75	5.15
2006	0.75	25.00	21.00	32.50	5.00
2007	0.75	25.00	21.00	32.50	5.00
2008 - 2014	0.75	25.00	21.00	32.50	5.00
Escalate thereafter	–	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr

The following table contains a reconciliation of APF's proved plus probable reserves for the most recently completed calendar year. Additional information required under NI 51-101 will be included in the Annual Information Form to be filed for fiscal 2003 and will be available at www.sedar.com and www.apfenergy.com by the end of April.

Reconciliation of Proved Plus Probable Reserves

	Natural Gas (mmcf)		Light & Medium Oil (mbbl)		Heavy Oil (mbbl)		NGL's (mbbl)		Total (mboe)	
	Gross (1)	Net (2)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves at December 31, 2002(3)	68,290	54,739	19,490	16,952	270	258	847	621	31,989	26,954
Extensions	2,375	1,943	390	327	–	–	7	5	793	656
Improved recovery	837	683	148	126	317	280	1	1	606	521
Technical revision	2,858	2,604	746	751	245	180	(10)	(27)	1,457	1,338
Discoveries	857	605	4	4	–	–	–	–	147	105
Acquisitions	36,659	30,424	2,982	2,648	2,579	2,374	437	300	12,107	10,393
Dispositions	(343)	(262)	(2,171)	(1,902)	–	–	–	–	(2,228)	(1,945)
Production	(12,336)	(9,748)	(1,955)	(1,643)	(407)	(347)	(131)	(95)	(4,549)	(3,710)
Reserves at December 31, 2003	99,197	80,988	19,634	17,263	3,003	2,745	1,151	805	40,322	34,311

Columns may not add due to rounding

(1) Gross reserves for the purposes of this analysis are defined as total Company Interest Reserves. "Company Interest Reserves" are defined as working interest reserves (before the deduction of royalties) plus royalty interest reserves.

(2) Net reserves for the purpoes of this analysis are defined as net after royalty reserves.

(3) Reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties for 2002 and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

Corporate Development

In 2003 APF completed three corporate and several asset acquisitions for a total value of approximately $167 million, making it the most prolific period of growth in APF's seven-year history.

APF evaluates assets based on two criteria: the buying opportunity and the upside potential. The Trust's Corporate Development team is comprised of individuals with expertise in geology, engineering, land management and finance. In 2003, the Trust completed corporate and asset transactions worth approximately $167 million, making it the most prolific period of growth in APF's seven-year history. Over the course of the year, APF evaluated almost $5 billion in potential acquisitions before executing on those offering the best buying opportunities and upside potential.

The bulk of the 2003 activity was reflected in three corporate transactions, which increased the Trust's gas weighting to approximately 45% of the asset mix, and gained access to long-life CBM properties in Alberta and Wyoming. The Trust continued to consolidate its interest in a number of core areas, acquiring production at Countess, Queensdale and Vermilion throughout the year. A portfolio review of APF's properties resulted in the divestiture of approximately 533 boe/d of non-core assets and the farm-out of higher risk exploration lands. APF will continue to search for new opportunities that add value to an already strong asset base.

ACQUISITION OF HAWK OIL INC.

On February 5, 2003, APF acquired Hawk Oil Inc., a Calgary-based gas levered producer for a total cost of $49.1 million. At the time of the acquisition, Hawk's production was 2,700 boe/d consisting of 9.3 mmcf/d of gas (61%) and 1,150 bbls/d of oil (39%). Assets acquired in this transaction served to further increase APF's presence in Central Alberta. In addition, Hawk had a heavy oil portfolio that offered diversity to APF's existing asset base. In the aggregate, the assets had an average 98% working interest and included natural gas interests at Paddle River, Vermilion and Holmberg, along with heavy oil in the Lloydminster and Epping areas. The

Heather Rampersaud

Pat Morris

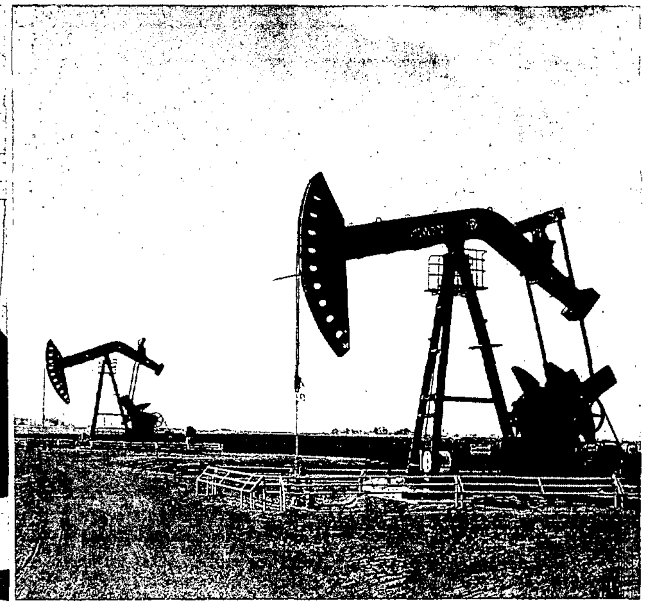
transaction included approximately 37,000 net acres of undeveloped land and an extensive proprietary seismic database.

ACQUISITION OF NYCAN ENERGY CORP.

On April 23, 2003, APF acquired approximately 1,265 boe/d through the purchase of Nycan Energy Corp. for $42.4 million. Daily volumes were comprised of 5,700 mcf/d of gas (77%) and 315 bbls/d of oil and natural gas liquids (23%) of which 65% was operated. The acquisition complemented APF's existing asset base in Southeast Alberta and further increased the Trust's gas weighting. The major assets included interests at Carmangay, Enchant, Little Bow, Long Coulee, Retlaw and Turin. The acquisition also included approximately 58,000 net undeveloped acres of land.

ACQUISITION OF CANSCOT RESOURCES LTD.

On September 26, 2003, APF acquired CanScot Resources Ltd., a coalbed methane ("CBM") producer with operations in both Canada and the Unites States, for a total consideration of $42.1 million. Conventional production at the time of purchase was approximately 800 boe/d, consisting of 3,900 mcf/d of gas (81%) and 150 bbls/d of oil. The transaction comprised a focused group of high working interest long-life conventional and CBM properties in Alberta and Wyoming and included approximately 45,800 net acres of undeveloped land. Key CanScot staff joined APF, bringing with them extensive CBM experience in both Canada and the United States.



Left to right: Kellie D'Hondt, Chris Palacz

ASSET TRANSACTIONS

On May 29, 2003 APF acquired incremental production of 1.2 mmcf/d and deep hole rights at Countess, its largest gas property, in Southeast Alberta, for $7.03 million. The average working interest was 73%. In addition to the long-life production, the acquisition provided the Trust with several development prospects in the deeper Mannville and Basal Colorado formations.

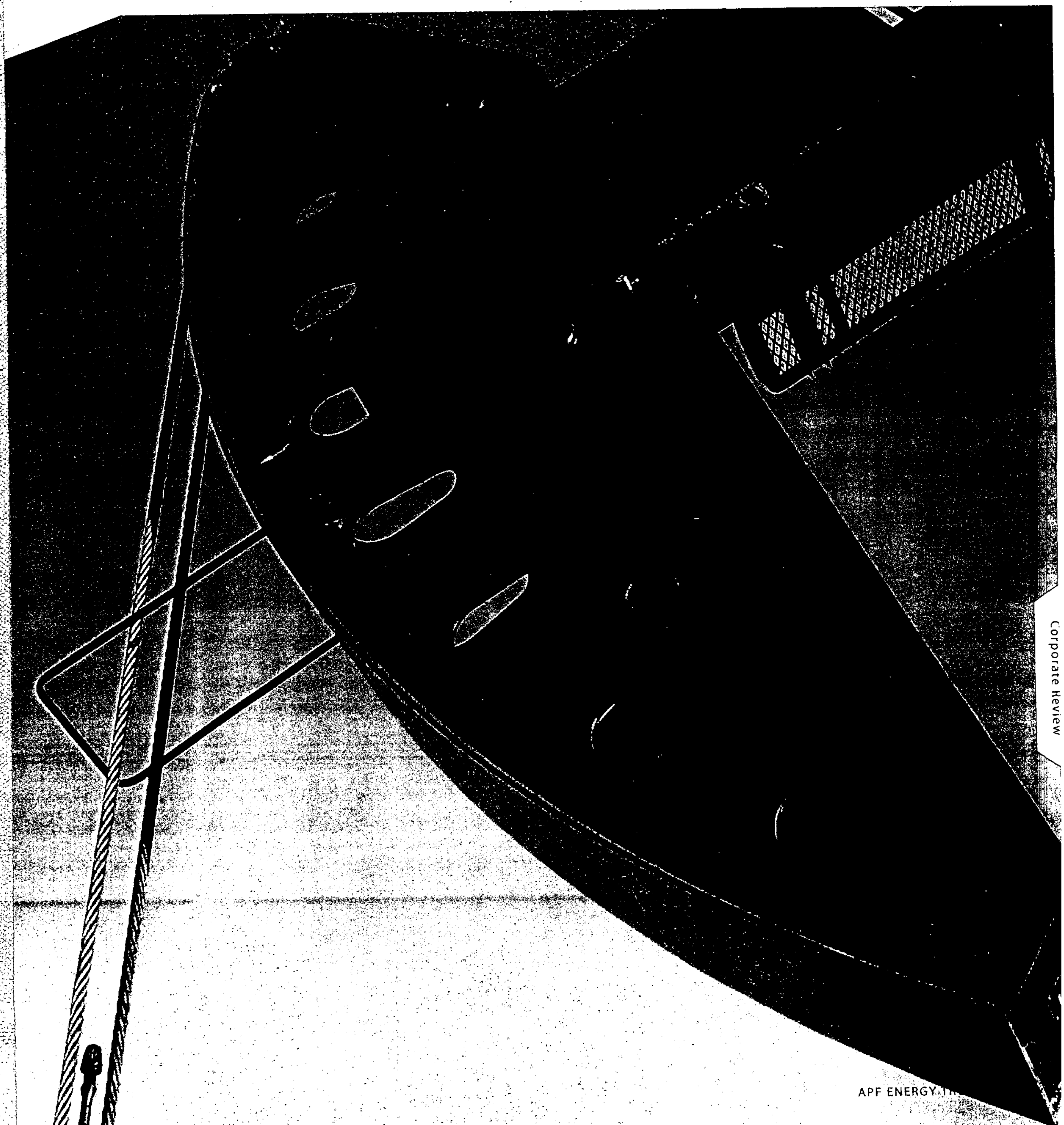
On July 30, 2003, APF acquired a 2.55% interest in the Swan Hills Unit No. 1, which added approximately 380 boe/d of production (89% light oil). APF initially signed a purchase and sale agreement with the vendor, for 17% of the Unit for $91.8 million, that was subject to certain rights of first refusal ("ROFR") by another party. The party exercised the ROFR, which resulted in APF receiving a small interest of the Unit for approximately $15.9 million. The Swan Hills assets are characterized by long-life, low-decline production and high quality, light gravity oil (41 degree API). The operator, a senior oil and gas producer, is continuing to develop the reservoir through reef and edge/infill drilling and miscible flood exploitation.

Land Holdings

	Developed Land		Undeveloped Land		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	450,251	204,878	422,156	236,039	872,407	440,917
BC	1,979	387	–	–	1,979	387
Manitoba	161	27	966	412	1,127	439
Saskatchewan	62,247	30,262	156,524	77,172	218,771	107,434
Wyoming	4,754	1,047	20,696	7,812	25,450	8,859
Total	519,392	236,601	600,342	321,435	1,119,734	558,036

In addition to the oil and gas reserves, GLJ also valued APF's 321,435 acres of net undeveloped land, at $19.1 million. The value was derived by reference to land sales proximate to APF's undeveloped acreage, the applicable working interest and expiry profile.

Corporate Review



Business Objectives

Christine Ezinga

Jesse Meidl

The goal of APF Energy Trust is to provide unitholders with stable cash distributions and strong total returns. To achieve this, the Trust must continually replace production with new reserves, either through internal drilling and optimization initiatives or through accretive acquisitions.

In order to replace these reserves and achieve growth, APF must be able to successfully identify development prospects and evaluate acquisition opportunities. The Trust has demonstrated an ability, throughout its history, to complete acquisitions at favourable metrics, resulting in high and stable cash distributions for unitholders. APF will continue to utilize its internal expertise to optimize its inventory of undeveloped land and to assess potential acquisitions.

EQUITY ISSUES

APF completed its initial public offering for $35 million on December 16,1996. Since then, the Trust has issued an additional 33.9 million units, raising approximately $345 million in equity to fund growth and development initiatives. APF will continue to issue equity from time to time, to finance acquisitions and capital budget requirements.

Type	Date	Unit Price ($)	Units (000)	Gross Proceeds ($000)
IPO	Dec-96	10.00	3,500	35,000
New issue	Dec-98	8.00	2,260	18,080
New issue	Mar-00	7.30	1,223	8,928
New issue	Mar-01	10.00	3,301	33,010
Acquisition	Apr-01	10.05	902	9,061
New issue	Jun-01	11.50	3,050	35,075
Private placement	Oct-01	9.55	1,080	10,314
New issue	Feb-02	9.75	3,250	31,688
Acquisition	May-02	10.15	3,385	34,358
Acquisition	Feb-03	9.45	3,990	37,708
New issue	Apr-03	10.40	5,352	55,670
Acquisition	Sep-03	11.50	1,342	15,433
New issue	Feb-04	11.60	4,765	55,300
Total			37,400	379,625

Left to right: Alan MacDonald, VP Finance; Steve Cloutier, President

DISTRIBUTIONS

Cash distributions are paid monthly to unitholders of record on the applicable record date. APF's record date is the last trading day of the month. In order to be a unitholder on the record date, units must have been purchased prior to the ex-distribution date, which is two trading days earlier. Key dates for 2004 are set out in this annual report. Purchases of units which settle on or after the ex-distribution date are not eligible for that month's distribution, but will qualify for the next month's distribution. Payments are made to unitholders on the 15th of the following month (if the 15th day of the month falls on a holiday or weekend, the distribution is paid the next business day). Since inception, the Trust has distributed $13.83 per unit to December, 2003, or an average of $1.98 per year.

DISTRIBUTION REINVESTMENT PLAN

On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003. The DRIP allows eligible Unitholders to reinvest their proceeds in additional Trust units at a price equal to 95% of the volume-weighted average price over a certain period, or receive a cash payment equal to 102% of the regular distribution.

Historical Distributions

Distribution Date ($)	**2003**	2002	2001	2000	1999	1998	1997
January 15th	**0.160**	0.150	0.220	0.125	0.120	0.475	0.210
February 15th	**0.160**	0.150	0.250	0.125	0.160	-	-
March 15th	**0.165**	0.150	0.250	0.125	0.120	0.120	-
April 15th	**0.185**	0.150	0.225	0.125	0.120	0.120	0.455
May 15th	**0.185**	0.150	0.300	0.125	0.160	0.175	-
June 15th	**0.200**	0.150	0.300	0.135	0.120	0.120	-
July 15th	**0.200**	0.150	0.300	0.135	0.120	0.120	0.420
August 15th	**0.200**	0.150	0.300	0.135	0.135	0.175	-
September 15th	**0.200**	0.150	0.250	0.140	0.125	0.120	-
October 15th	**0.175**	0.150	0.250	0.210	0.125	0.120	0.425
November 15th	**0.175**	0.150	0.200	0.210	0.125	0.175	-
December 15th	**0.175**	0.150	0.200	0.310	0.125	0.120	-
Total	**2.180**	1.800	3.045	1.900	1.555	1.840	1.510
Cumulative Total	**13.830**	11.650	9.850	6.805	4.905	3.350	1.510

Key 2004 Distribution Dates

JANUARY

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	**15**	16	17
18	19	20	21	22	23	24
25	26	27	**28**	29	**30**	31

FEBRUARY

S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	**16**	17	18	19	20	21
22	23	24	**25**	26	**27**	28
29						

MARCH

S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	**15**	16	17	18	19	20
21	22	23	24	25	26	27
28	**29**	30	**31**			

APRIL

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	**15**	16	17
18	19	20	21	22	23	24
25	26	27	**28**	29	**30**	

MAY

S	M	T	W	T	F	S
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	**17**	18	19	20	21	22
23/30	24/31	25	26	**27**	28	29

JUNE

S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	**15**	16	**17**	**18**	19
20	21	22	23	24	25	26
27	**28**	29	**30**			

JULY

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	**15**	16	17
18	19	20	21	22	23	24
25	26	27	**28**	29	**30**	31

AUGUST

S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	**16**	17	18	19	20	21
22	23	24	25	26	**27**	28
29	30	**31**				

SEPTEMBER

S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	**15**	16	17	18
19	20	21	22	23	24	25
26	27	**28**	29	**30**		

OCTOBER

S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	**15**	16
17	18	19	20	21	22	23
24/31	25	26	**27**	28	**29**	30

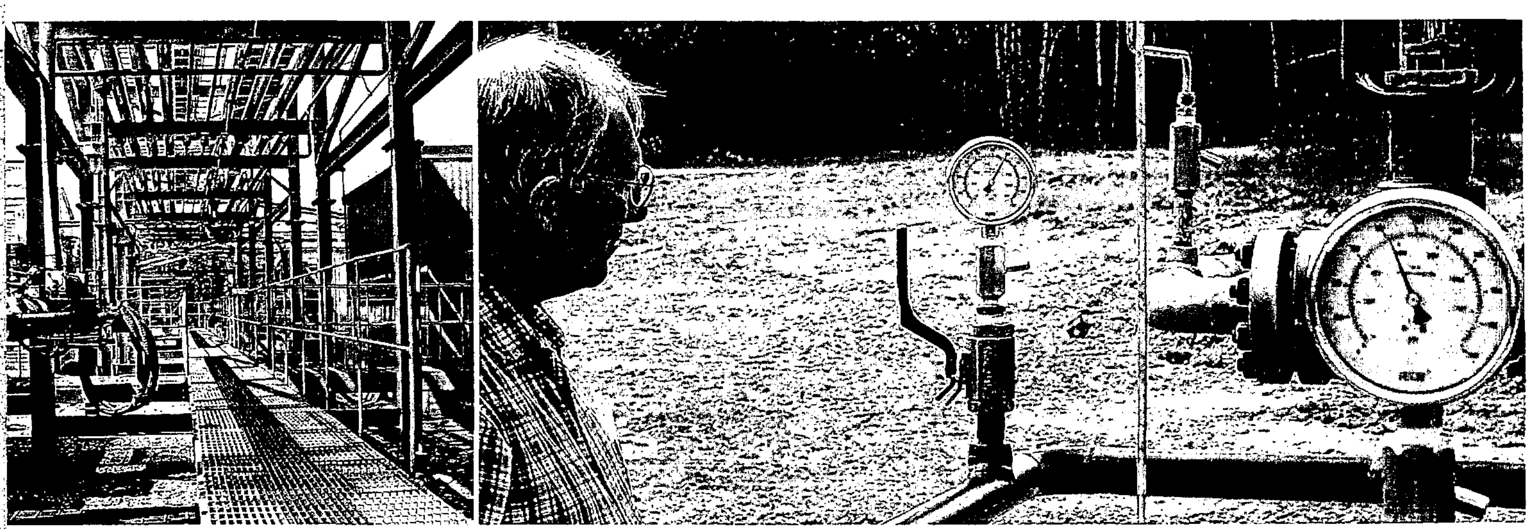
NOVEMBER

S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	**15**	16	17	18	19	20
21	22	23	24	25	**26**	27
28	29	**30**				

DECEMBER

S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	**15**	16	17	18
19	20	21	22	23	24	25
26	27	28	**29**	30	**31**	

Distribution Date **Ex-Distribution Date** **Record Date**



Bob Wilshusen

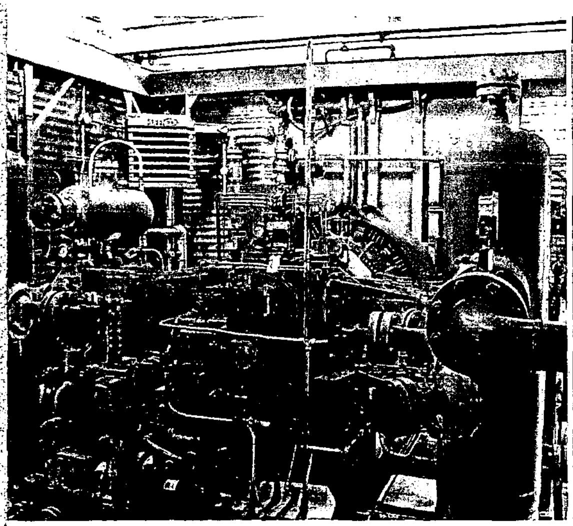
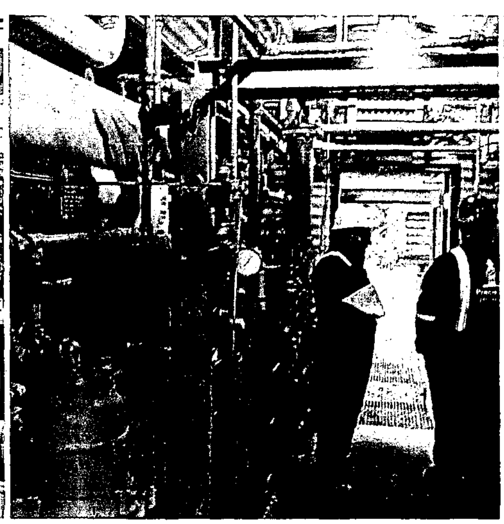
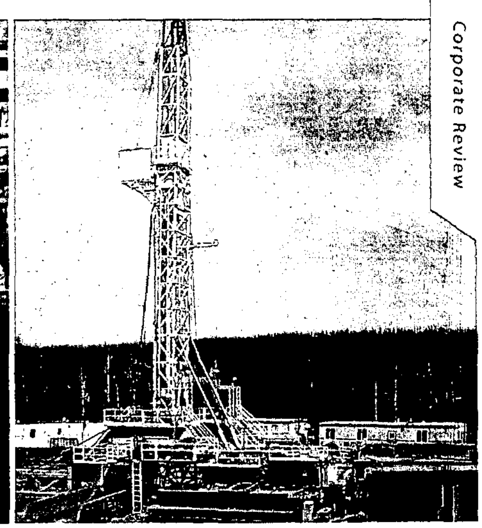
Taxation

Distributions have two components for taxation purposes: the taxable portion, which is a return on capital; and the tax deferred return of capital, which reduces the unitholder's adjusted cost base each time a distribution is paid out. APF provides a summary to unitholders, on an annual basis, illustrating what portion is taxable and what portion is a return of capital. The following table summarizes the breakdown of distributions paid by the trust since inception.

	Total Distributions	Income		Return of Capital	
	($)	($)	(%)	($)	(%)
2003	**2.18**	**1.72**	**78.81**	**0.46**	**21.19**
2002	1.80	1.14	63.52	0.66	36.48
2001	3.05	1.74	57.18	1.30	42.83
2000	1.90	1.18	62.14	0.72	37.86
1999	1.55	0.53	33.83	1.03	66.17
1998	1.84	0.45	24.63	1.39	75.38
1997	1.51	0.60	39.54	0.91	60.46
Total	13.83	7.36		6.47	

Distributions paid by the Trust to non-corporate unitholders who are U.S. residents or citizens are to be treated as "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003, and are generally eligible for the reduced U.S. dividend tax rate.

On March 23, 2004, the federal budget proposed that the tax treatment of distributions to non-residents be changed so that the deemed capital portion of distributions to non-residents will now be taxed at a rate of 25% (reduced to 15% for U.S. residents). From a practical perspective this will not impact APF as our Trustee has historically always applied the withholding tax on the full amount of our distributions, and not just the income portion.

Corporate Governance

APF is committed to ensuring that its governance structure provides unitholders with the highest degree of confidence that the Trust's business and operations are being conducted with the unitholders' interests in mind.

The relationship between the Board and management of APF is built around the mutual understanding of their respective roles and the ability of the Board to act independently in carrying out its responsibilities. The Board's participation in strategic planning recognizes that the role of directors is not to manage on a day-to-day basis, but to provide stewardship to management in executing the overall business strategies of APF. The Board oversees and monitors the management of risks and regularly reviews the status of the business plan management.

All directors are elected by unitholders. Voting for directors is conducted during APF's annual general meeting. The APF Board is comprised of individuals who have a diversity of experience and business knowledge, and has increased in size to accommodate the growth and complexity of the Trust. In keeping with best practices, the roles of the Chairman and Chief Executive Officer are separate.

The Board meets regularly to discuss the Trust's operations and business. When circumstances warrant, additional meetings are scheduled to deal with time-sensitive or special situations. Excluding special meetings and monthly meetings to set the cash distribution, the Board meets quarterly with management to review major operational and financial aspects of APF. Also, the unrelated directors meet independently of the related directors when circumstances warrant.

Governance is the responsibility of the full Board. The Board is tasked with reviewing its size and composition and that of its committees. The Board has open access to the Trust's legal advisors at all times and may retain independent counsel if circumstances warrant.

INDEPENDENCE OF THE BOARD

The Board is currently comprised of six members. Four of the six are unrelated directors and the remaining two are represented by APF's Chief Executive Officer and the President. The Board ensures that APF discloses on an annual basis the number of related and unrelated directors.

COMMITTEES

The Board has three committees: Audit, Reserves and Compensation. The committees have formal written mandates that are reviewed annually, taking into account changes in regulatory requirements or practices. Changes are proposed to the Board as deemed necessary.

Audit Committee

The Audit Committee is comprised of all the unrelated Directors. All committee members possess the requisite financial skills to qualify them as members. The Audit Committee meets at least quarterly with management and the external auditors to review the quarterly and annual financial statements and also meets independently with the auditors at least twice annually.

Reserves Committee

The Reserves Committee is comprised of all the unrelated Directors. The Reserves Committee oversees the integrity of APF's reserve estimates and carries out its duties in accordance with NI 51-101. The Committee meets at least twice per year with management and the independent engineering consultants. The Committee is also responsible for overseeing those procedures and policies that minimize environmental, occupational safety and health risk, as APF dedicates itself to achieving the highest standards of performance.

Compensation Committee

The Compensation Committee is comprised of two unrelated Directors and the President. The committee is responsible to the Board for overseeing the development of competitive compensation policies designed to attract, develop and retain employees of the highest standards at all levels. It is responsible for recommending to the Board the compensation arrangements for senior officers and oversees the administration of succession planning. The committee reviews Directors' compensation and makes recommendations as deemed necessary.

In conjunction with proposed corporate governance standards, the President of APF will resign from the committee and all members will be unrelated following the Annual General Meeting.

APF is committed to protecting the health and safety of all individuals affected by our activities. Through the office of the Environment, Health and Safety Coordinator, execution of our policies ensures that the Trust safeguards the environment and contributes to the well-being of the communities in which we live and operate.

ENVIRONMENT

APF continues to promote guidelines, standards and procedures that support our environmental policy. This commitment is demonstrated by setting objectives to actively foster continual improvement. APF meets or exceeds all applicable government regulations and industry codes of practice relating to environmental protection, and works with those organizations in the furtherance and development of appropriate policies.

In 2003, APF became a member of the Environment, Health and Stewardship program initiated by the Canadian Association of Petroleum Producers. Participation in this program demonstrates a commitment to industry and corporate excellence in environmental, health and safety performance and will facilitate communication to all stakeholders.

The Trust implemented a comprehensive auditing program to ensure that environmental liabilities are identified and corrected. An environmental inventory management system has been established, allocating funds on an annual basis, to actively manage any potential for liabilities.

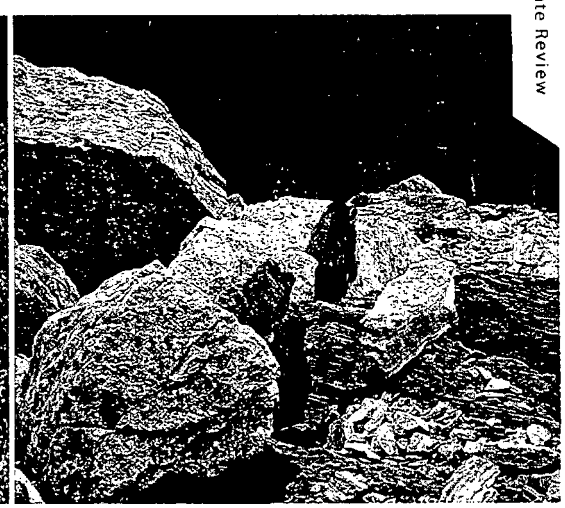
HEALTH AND SAFETY

APF has established measurable performance targets relating to the health and safety of employees and contractors. Regular meetings and training programs are conducted to review and discuss health and safety regulations and workplace practices and procedures so that all employees and contractors have the skills necessary to attain these goals. Occupational health and safety is systematically managed and integrated into all business decisions, plans and operations, maintaining compliance with applicable laws, regulations and policies.

Emergency response plans and procedures are continually assessed to ensure APF can react effectively and efficiently to incidents, thus minimizing any possible impact. Simulation events are conducted on a regular basis so emergency response plans remain current and appropriate.

APF promotes consultation with the public, government agencies and other stakeholders regarding the Trust's operations and is responsive to their concerns. Third party and internal audits of APF operations are conducted to identify risks and initiate proactive steps to reduce or prevent exposure.

Environment, health and safety aspects and the impacts of all proposed activities are assessed on an ongoing basis so appropriate hazard control measures can be designed and implemented. Excellence is achieved through the support and active participation of all management, employees and contractors working for APF. Our policy is reviewed annually and modified as appropriate.

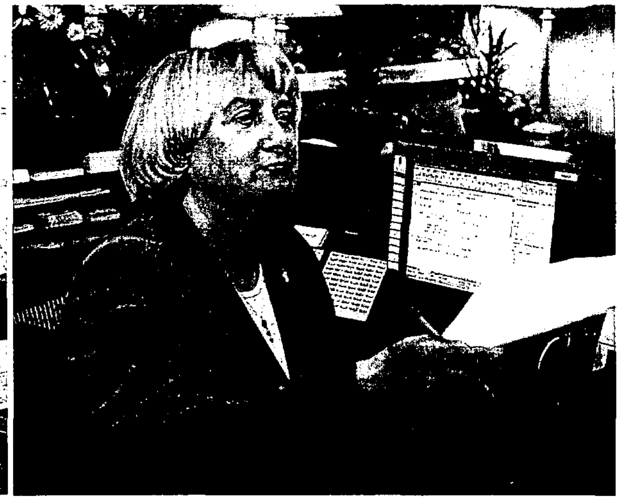


Members of the APF Team hike to the Burgess Shale, a world renowned geological location in British Columbia.

Corporate Social Responsibility

Glenn Miller

Jason Thompson



Margaret Gilchrist

APF is committed to fostering ongoing positive relationships between our business and stakeholders through the implementation of a Corporate Social Responsibility ("CSR") program. The socio-economic well-being of our communities and those who work and live in them is directly linked to the success of APF.

OUR EMPLOYEES

APF is continually striving to be an employer of choice, emphasizing the value of work-life balance for employees. Corporate fitness facilities and active interaction on a social level result in a more productive and engaged group of professionals. Ongoing opportunities for continuing education are provided and employees are encouraged to participate in the decision-making process of the business.

OUR BUSINESS PARTNERS AND COMMUNITIES

APF seeks out business partners with similar values. These entities must not engage in activity that would harm the environment or compromise surrounding communities. Any such activity has the potential of putting APF and its reputation at risk.

APF's Environment, Health and Safety program forms an integral part of the Trust's CSR initiative. The Trust's Environment, Health and Safety Co-ordinator and Manager of Surface Land and Community Affairs work closely with those most affected by APF's field operations to ensure that we are the best possible partner in the community.

Currently, APF invests in the future of our communities through gifts to charities and service clubs and the sponsorship of events. Many of our employees volunteer time to a diverse range of organizations sharing with them their skills and passions.

In 2003, APF contributed to a wide-ranging field of charities and service clubs including: Alberta Cancer Foundation, Inn from the Cold Society, R. B. Bennett Elementary School in Calgary, and a host of minor league sporting teams across Alberta and Saskatchewan.

INVESTORS

APF's unitholders expect their interests in oil and gas assets to be managed in an effective and efficient manner, with a view to balancing the economic value of their investment with the interests of the community. Through APF's CSR plan, unitholders have ongoing disclosure of the Trust's performance and goals, making it easier for them to evaluate APF from a more dynamic perspective.

Management's Discussion and Analysis

The following discussion should be read in conjunction with the audited consolidated financial statements included in this annual report. The financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars. Additional information relating to APF, including disclosures required under National Instrument 51-101, can be found in APF's Annual Information Form ("AIF") on SEDAR at www.sedar.com or on APF's website at www.apfenergy.com.

PRODUCTION

During the fourth quarter, production increased by 38% over the same period in 2002. Production volumes for the year were 46% higher in 2003, due primarily to the acquisitions of Hawk Oil Inc. ("Hawk"), Nycan Energy Corp. ("Nycan") and CanScot Resources Ltd. ("CanScot"). Natural production declines were partially offset throughout the year by production increases from successful development drilling programs at Queensdale, Macoun and Tatagwa in Southeast Saskatchewan and at Countess in Southeast Alberta. A $40 million capital expenditure budget has been set forth in 2004 and is expected to maintain production levels at the 2003 exit rate of approximately 13,000 boe/d.

	Three Months Ended December 31			Year Ended December 31		
	2003	2002	% Change	**2003**	2002	% Change
Crude oil (bbl/d)	**6,499**	6,001	8	**6,472**	5,307	22
Natural gas (mcf/d)	**36,929**	19,776	87	**33,799**	18,488	83
NGL (bbl/d)	**474**	187	153	**358**	144	149
Total (boe/d) (1)	**13,128**	9,484	38	**12,463**	8,532	46
Production split						
Oil & NGL's	**53%**	65%		**55%**	64%	
Natural gas	**47%**	35%		**45%**	36%	

(1) Boe's may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), 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.

MARKETING

In 2003, APF's production mix was 55% crude oil and NGL's and 45% natural gas. Crude oil was sold under 30-day evergreen contracts while approximately 25% of natural gas production was sold to aggregators pursuant to long-term contracts, with the remaining 75% sold on the spot market.

PRICES

During the fourth quarter of 2003, price realizations declined a modest 3% for the same quarter in 2002, due largely to a 16% decrease in the value of the U.S. dollar against the Canadian dollar. Oil pricing was most affected by the change in currency exchange rates, with price realizations decreasing by 12% while the benchmark West Texas Intermediate ("WTI") pricing increased 11% over the fourth quarter of 2002. Natural gas pricing during the quarter increased by 14% over the same period in 2002.

WTI oil prices averaged $U.S. 31.06 per bbl in 2003, 19% higher than the 2002 average of $U.S. 26.10. Crude oil prices in Canada are based on the WTI reference price, adjusted for transportation, differentials and foreign exchange. The price received by APF is based upon the refiners' posted price, less transportation and adjustments for APF's product quality relative to the posted price and adjusted for hedging. APF's oil price after hedging averaged $34.46 per bbl in 2003, compared with $33.66 per bbl in 2002, an increase of 2%.

Canadian oil prices were negatively impacted by an average 11% decrease in the value of the U.S. dollar versus the Canadian dollar during 2003. The NYMEX futures contracts for the remainder of 2004 suggest crude oil prices will exceed 2003 levels during the year.

APF's realized natural gas price after hedging for the year averaged $6.32 per mcf, 65% higher than the average realized price of $3.83 per mcf in 2002. This is consistent with the increase in the benchmark AECO price in Alberta, which increased by an average of 63% from 2002 levels. APF expects gas prices during 2004 to remain consistent with or exceed 2003 levels as supply concerns dominate the market.

	Three Months Ended December 31			Year Ended December 31		
Prices - After Hedging	**2003**	2002	% Change	**2003**	2002	% Change
Crude oil ($Cdn./bbl)	**$ 31.66**	$ 35.80	(12)	**$ 34.46**	$ 33.66	2
Natural gas ($Cdn./mcf)	**5.41**	4.74	14	**6.32**	3.83	65
NGL ($Cdn./bbl)	**31.37**	30.63	2	**31.82**	25.15	27
Total ($Cdn./boe)	**$ 32.03**	$ 33.14	(3)	**$ 35.95**	$ 29.65	21
Reference Pricing						
WTI ($U.S./bbl)	**$ 31.18**	$ 28.14	11	**$ 31.06**	$ 26.10	19
AECO gas ($Cdn./mcf)	**$ 5.59**	$ 5.25	6	**$ 6.67**	$ 4.08	63
Foreign exchange ($U.S./$Cdn.)	**$ 1.3157**	$ 1.5695	(16)	**$ 1.4010**	$ 1.5703	(11)

HEDGING

Commodity prices are susceptible to market fluctuations. APF actively manages commodity price risk by entering into hedging contracts to protect revenues from fluctuations in commodity prices. Hedging is intended to provide stability to cash distribution levels by fixing the price of commodities on a portion of the production portfolio. One of the key assumptions in the preparation of APF's annual budget and estimate of annual distributions is commodity price. APF's mandate is to ensure that a portion of the year's distributions, based on certain commodity price assumptions, are protected. APF looks for opportunities to sell forward a portion of its production at levels at, or better than, the commodity prices used in the budget process. While this guideline necessarily implies that commodity prices may rise, it must be acknowledged that commodity prices may fall. In this regard, in situations where commodity prices are below those used in the annual budget, management's expertise is relied upon to ensure that potential opportunities to mitigate the impact of lower commodity prices are executed. Hedging activities during 2003 reduced revenues by $3.56 million, reducing the realized oil price by $1.61 per bbl and increasing the natural gas price by $0.02 per mcf. At the time of printing APF had the following hedges in place:

Current Hedging Position

Period	Type of Commodity	Average Contract	Average Daily Quantity	Hedged Price
March 2004	Crude oil	Swap	3,000 bbls	$U.S. 30.76/bbl
March 2004	Natural gas	Swap	10,000 GJ	$Cdn. 7.19/GJ
March 2004	Natural gas	Physical	2,000 mmbtu	$U.S. 7.00/mmbtu
April to June 2004	Crude oil	Swap	2,500 bbls	$U.S. 30.78/bbl
April to June 2004	Natural gas	Swap	10,333 GJ	$Cdn. 5.76/GJ
April to June 2004	Natural gas	Swap	1,000 mmbtu	$U.S. 5.19/mmbtu
July to September 2004	Crude oil	Swap	2,167 bbls	$U.S. 29.58/bbl
July to September 2004	Natural gas	Swap	10,000 GJ	$Cdn. 5.75/GJ
July to September 2004	Natural gas	Swap	1,000 mmbtu	$U.S. 5.19/mmbtu
October to December 2004	Crude oil	Swap	1,833 bbls	$U.S. 30.45/bbl
October to December 2004	Natural gas	Swap	3,333 GJ	$Cdn. 5.75/GJ
October to December 2004	Natural gas	Swap	333 mmbtu	$U.S. 5.19/mmbtu
January 2005	Crude oil	Swap	1,000 bbls	$U.S. 31.74/bbl

In addition to commodity hedging, APF has also entered into foreign currency hedge contracts in order to mitigate currency risk. The Trust has hedged $U.S. 20 million of revenue at a rate of $Cdn. 1.3317 or $U.S. 0.7509 for calendar 2004.

At December 31, 2003, APF had fixed the interest rate on a portion of its debt as follows:

Term	Amount (000)	Interest Rate
January 2004 to February 2005	$ 20,000	3.67% plus stamping fee
January 2004 to May 2005	$ 20,000	3.75% plus stamping fee
January 2004 to November 2005	$ 20,000	3.58% plus stamping fee

REVENUES

Revenues for the fourth quarter of 2003, net of hedging, increased to $39 million from $29 million during the fourth quarter of 2002. Increased revenues from natural gas contributed to 46% of total revenue in the fourth quarter of 2003, an increase of $9.2 million over the same period in the previous year.

Annual revenues, net of hedging transactions increased 76% to $165 million in 2003, due to a combination of higher production volumes and higher commodity prices.

	Three Months Ended December 31				Year Ended December 31			
Oil and Gas (000 except per boe amounts)	**2003**	**% of Total**	2002	% of Total	**2003**	**% of Total**	2002	% of Total
Crude oil sales	**$ 19,536**	**50**	$ 20,948	71	**$ 85,193**	**51**	$ 69,390	74
Natural gas sales	**17,830**	**46**	8,624	29	**77,747**	**47**	25,534	27
NGL sales	**1,367**	**3**	527	2	**4,157**	**3**	1,320	1
Hedging	**(44)**	**–**	(1,180)	(4)	**(3,565)**	**(2)**	(3,899)	(4)
Other	**421**	**1**	461	2	**1,925**	**1**	1,676	2
Total revenue	**39,110**	**100**	29,380	100	**165,457**	**100**	94,021	100
Per boe	**$ 32.38**		$ 33.67		**$ 36.37**		$ 30.19	

ROYALTIES

For the fourth quarter, royalties as a percentage of revenue were 5% higher in 2003, as a result of higher commodity pricing. Royalties per barrel of oil equivalent produced were 19% higher in 2003, consistent with the increase in commodity prices during the year. Royalties as a percentage of revenues were essentially unchanged.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Crown royalties	**$ 4,838**	$ 2,862	69	**$ 19,364**	$ 10,905	78
Freehold royalties	**2,120**	2,310	(8)	**10,193**	6,323	61
Overriding royalties	**609**	265	130	**2,916**	1,479	97
Total royalties	**$ 7,567**	$ 5,437	39	**$ 32,473**	$ 18,707	74
% of revenue after hedging	**19.3%**	18.5%	5	**19.6%**	19.9%	(1)
Per boe	**$ 6.26**	$ 6.23	–	**$ 7.14**	$ 6.01	19

OPERATING COSTS

Fourth quarter operating costs increased by 16% over the same period in 2002, while annual costs increased by 12% in 2003 to average $7.12 per boe. Increases were primarily due to initial field optimization costs on newly acquired properties and higher energy costs. Continued high energy costs and general higher field costs associated with APF's current property portfolio are expected to negate any operating efficiencies initiated to reduce operating costs in 2004.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Operating costs	**$ 9,619**	$ 5,970	61	**$ 32,370**	$ 19,748	64
Per boe	**$ 7.97**	$ 6.84	16	**$ 7.12**	$ 6.35	12

NETBACKS

Netbacks decreased from $20.60 per boe in the fourth quarter of 2002 to $18.15 per boe during the fourth quarter of 2003, resulting from lower revenues which were negatively impacted by currency exchange rates and a 16% increase in operating costs. Higher commodity prices during 2003 offset increased royalty expenses and operating costs during 2003, resulting in annual operating netbacks of $22.11/boe, a 24% increase from 2002.

	Three Months Ended December 31			Year Ended December 31		
($ per boe)	**2003**	2002	% Change	**2003**	2002	% Change
Net revenue (after hedging)	**$ 32.38**	$ 33.67	(4)	**$ 36.37**	$ 30.19	20
Royalties	**(6.26)**	(6.23)	–	**(7.14)**	(6.01)	19
Operating costs	**(7.97)**	(6.84)	16	**(7.12)**	(6.35)	12
Netback	**$ 18.15**	$ 20.60	(12)	**$ 22.11**	$ 17.83	24

GENERAL AND ADMINISTRATIVE

General and administrative costs increased in absolute terms for both the quarterly and annual periods of 2003, by 157% and 116% respectively, compared with 2002. The increase is due primarily to costs associated with the increase in staffing levels from recent corporate and property acquisitions and the cost of APF's short-term incentive plan ("STIP"), which was introduced for 2003 following the termination of the management contract.

The STIP was created to encourage and reward outstanding employee performance and to ensure that the interests of both the unitholders and employees were aligned. The STIP enables all eligible employees to participate in a bonus pool, provided APF generates at least a 10% total annual return. Total annual return is calculated as distributions paid during the year plus or minus the change in unit price compared with the previous year-end. When the 10% total return threshold is met, a portion of net operating income ("NOI") is allocated to the bonus pool and shared by all eligible employees. The total return on APF units for the year ended December 31, 2003 was 50%. Based on this total return, the bonus pool under the STIP for the year was $3.35 million (2002 - $nil). Senior employees, including officers, may also be eligible to receive performance bonuses based on criteria applicable to each individual's responsibilities. Excluding the STIP, general and administrative costs per boe for the year ended December 31, 2003 were $1.47.

APF's success at finding and developing oil and gas reserves is due to its ability to recruit highly competent individuals with strong technical skill sets. Accordingly, APF's compensation structure is designed to provide employees with a competitive base package and the potential to enhance the base, provided unitholders experience strong returns.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
General and administrative	**$ 3,980**	$ 1,547	157	**$ 10,023**	$ 4,635	116
Per boe	**$ 3.30**	$ 1.77	86	**$ 2.20**	$ 1.49	48

MANAGEMENT FEE

Prior to the internalization of the management contract, the Manager received a management fee equal to 3.5% of net production revenue. During 2002, management fees amounted to $1.98 million ($0.63 per boe) compared with $0.65 million ($0.75 per boe) for the fourth quarter 2002. Commencing January 1, 2003, no management fees were payable.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Management fee	**$ –**	$ 654	(100)	**$ –**	$ 1,976	(100)
Per boe	**$ –**	$ 0.75	(100)	**$ –**	$ 0.63	(100)

INTEREST

Interest expense increased 27% and 47% for the fourth quarter and year ended 2003 respectively. The increases were due to higher average debt levels arising from the various corporate and property acquisitions completed during 2003. At December 31, 2003, APF had fixed the interest rate on $60 million of debt (2002 - $30 million) at an average rate of 3.67% (2002 - 3.76%) plus applicable stamping fee, maturing in 2005.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Interest	**$ 1,087**	$ 854	27	**$ 4,171**	$ 2,834	47
Per boe	**$ 0.90**	$ 0.98	(8)	**$ 0.92**	$ 0.91	1

DEPLETION, DEPRECIATION AND AMORTIZATION

Depletion, depreciation and amortization ("DD&A") increased by 68% per boe in the fourth quarter of 2003 from the same period in 2002 and 14% for the year to $13.90 and $11.08 per boe respectively. The increases reflect the current year's acquisitions being higher than the historical average cost per boe.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Depletion and amortization	**$ 16,791**	$ 7,226	132	**$ 50,417**	$ 30,200	67
Per boe	**$ 13.90**	$ 8.28	68	**$ 11.08**	$ 9.70	14

SITE RESTORATION

Site restoration increased by 4% per boe during the fourth quarter from the same period in 2002 and by 9% to $0.73 per boe for the year, reflecting the future incremental site reclamation costs associated with acquisitions completed during 2003.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Site restoration	**$ 827**	$ 576	44	**$ 3,327**	$ 2,087	59
Per boe	**$ 0.69**	$ 0.66	4	**$ 0.73**	$ 0.67	9

COMPENSATION EXPENSE

During 2003, as part of APF's long-term incentive plan, 1,538,250 Trust unit incentive rights (2002 – 441,233) were issued to employees and directors, at prices ranging from $9.67 to $11.54 per Trust unit (2002 - $9.73 to $10.80). The exercise price of the rights is adjusted downward over time by the amount, if any, that quarterly distributions exceed 2.5 % of the net book value of property, plant and equipment. The rights have a 10-year term and vest in one-third increments on the first, second and third anniversaries of their grant. Rights to purchase 1,824,330 Trust units at an average adjusted exercise price of $9.09 were outstanding at December 31, 2003. These rights have an average remaining contractual life of 9.3 years and expire at various dates to September, 2013. There were 47,221 rights exercisable at December 31, 2003 (2002 – nil).

APF has prospectively adopted the CICA Handbook Section 3870 – "Stock Based Compensation". Under the transitional adoption rules, companies that prospectively adopt at December 31, 2003 are only required to recognize compensation expense for those options granted during 2003, with proforma disclosure of options granted during 2002.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Compensation expense	**$ 582**	$ –	100	**$ 1,241**	$ –	100
Per boe	**$ 0.48**	$ –	100	**$ 0.27**	$ –	100

APF adopted the new Handbook section during the fourth quarter of 2003. The first three quarters of 2003 have been restated as a result of adopting the standard. APF grants options annually. Compensation expense for the first quarter relates only to options granted in 2002.

	2003				2002			
(000)	**Q1**	**Q2**	**Q3**	**Q4**	Q1	Q2	Q3	Q4
Net income (loss) as reported	**$ 13,616**	**$ 21,137**	**$ 11,405**	**$ (2,528)**	$ 2,414	$ 4,429	$ 5,463	$ (942)
Compensation expense	**(8)**	**(217)**	**(434)**	**(582)**	–	–	–	–
Restated net income (loss)	**$ 13,608**	**$ 20,920**	**$ 10,971**	**$ (3,110)**	$ 2,414	$ 4,429	$ 5,463	$ (942)

TAXES

Saskatchewan capital tax and federal large corporation tax increased by 44% during the quarter and 43% for the year ended December 31, 2003 and reflects the higher proportion of business in the Province of Saskatchewan and higher paid up capital.

Future income taxes are recorded on corporate acquisitions to the extent the book value of assets acquired, excluding goodwill, exceeds the tax basis. This future income tax liability increases the book cost of the assets acquired. It is anticipated that the future income tax liability will not be paid by APF Energy, but will instead be passed on to unitholders along with the income. Accordingly, this income tax liability will reduce each year and will be recognized as an income tax recovery at that time, to the extent that no income taxes were paid by APF Energy. In 2003, APF recorded a recovery of income taxes of $14.3 million compared with $7.1 million in 2002, leaving a balance of $64.2 million in future income taxes payable at December 31, 2003.

During 2003, the Canadian government enacted Federal income tax changes for the oil and gas resource sector as outlined in its 2003 Budget. The federal income tax changes effectively reduced the statutory tax rates for current and future periods, resulting in a significant increase in the future tax recovery (a non-cash item) compared with the first quarter and prior years. Specifically, the current 100% deductibility of the resource allowance will be completely phased out by the year 2007. During the same time frame, Crown charges will become 100% deductible and resource tax rates will decline from the current 27% to 21%. APF realized a future income tax recovery of approximately $9 million during the second quarter relating to this income tax change.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Capital and other taxes	**$ 624**	$ 433	44	**$ 2,721**	$ 1,901	43
Per boe	**$ 0.52**	$ 0.50	4	**$ 0.60**	$ 0.57	5
Recovery of future income taxes	**$ 482**	$ 198	143	**$ (14,333)**	$ (7,134)	101

INTERNALIZATION OF MANAGEMENT CONTRACT

On December 18, 2002, the unitholders approved the internalization of management and effective December 31, 2002, the Trust acquired all of the shares of APF Energy Management Inc. The acquisition resulted in the elimination of all management fees including the 3.5% fee on net operating income, a structuring fee of 1.5% on acquisitions and dispositions and the 1% residual royalty.

The total purchase price of the shares, including transaction costs, was $10.9 million, of which $4.6 million was paid in cash and $6.3 million was paid with Trust units, a portion of which are subject to certain escrow provisions. Of the total, $7.3 million was recorded as an expense in 2002.

NET EARNINGS

Earnings were up 279% to $43.0 million or $1.32 per Trust unit ($1.21 diluted) in 2003 compared with $11.4 million or $0.55 per Trust unit ($0.55 diluted) in 2002. The increase is attributable to both increases in production and commodity prices received throughout 2003.

Earnings per unit in the fourth quarter of 2003 declined as a result of increased general and administrative as well as DD&A expenses. Net earnings for the fourth quarter of 2002 decreased primarily as a result of the one-time, $7.3 million internalization expense.

Selected Annual Information

(000 except per unit amounts)	**2003**	2002	2001
Total revenue	**$ 165,457**	$ 94,021	$ 69,924
Net earnings	**$ 43,048**	$ 11,365	$ 18,144
Per unit - basic	**$ 1.32**	$ 0.55	$ 1.44
Per unit - diluted	**$ 1.21**	$ 0.55	$ 1.44
Total assets	**$ 484,287**	$ 297,627	$ 198,176
Total long-term debt	**$ 98,000**	$ 88,000	$ 59,250
Distributions	**$ 68,713**	$ 37,766	$ 37,311
Per unit - basic	**$ 2.195**	$ 1.810	$ 2.980

APF's growth over the past year has been driven by the acquisitions of Hawk, Nycan and CanScot and an active development and optimization program. Growth in 2002 was positively impacted by drilling and the corporate acquisition of Kinwest Resources Inc. APF's natural gas production has increased as a percentage of total production in the past year with APF benefiting from strong gas prices, which are expected to remain strong in 2004.

SUMMARY OF QUARTERLY RESULTS

	2003				2002			
(000 except per unit amounts)	**Q1**	**Q2**	**Q3**	**Q4**	Q1	Q2	Q3	Q4
Revenue	**$ 44,502**	**$ 41,876**	**$ 39,970**	**$ 39,110**	$ 16,941	$ 21,495	$ 26,204	$ 29,380
Net earnings	**$ 13,616**	**$ 21,137**	**$ 11,405**	**$ (3,110)**	$ 2,414	$ 4,429	$ 5,463	$ (942)
Per unit - basic	**$ 0.54**	**$ 0.66**	**$ 0.32**	**$ (0.09)**	$ 0.14	$ 0.22	$ 0.25	$ (0.04)
Per unit - diluted	**$ 0.54**	**$ 0.65**	**$ 0.31**	**$ (0.09)**	$ 0.14	$ 0.22	$ 0.25	$ (0.04)

CAPITAL EXPENDITURES, ACQUISITIONS AND DISPOSITIONS

Net capital expenditures, including net property and corporate acquisitions, were $191 million in 2003 (2002 - $101 million). Of the total, $33.6 million was incurred for drilling and completions, geological, geophysical and production facilities expenditures, as APF continues to develop its asset base, with the remaining $158.1 million attributable to net property and corporate acquisitions. The 2003 corporate acquisitions of Hawk, Nycan and CanScot totalled $137.6 million, accounting for 72% of net capital expenditures during the year.

	Year Ended December 31		
(000)	**2003**	2002	% Change
Corporate acquisitions	**$ 137,622**	$ 62,143	121
Property acquisitions	**26,928**	27,958	(4)
Land acquisitions	**2,310**	616	275
Seismic	**1,070**	497	115
Drilling and completions	**24,287**	15,890	53
Production facilities	**7,749**	3,684	110
Other	**494**	908	(46)
Subtotal	**200,460**	111,696	79
Dispositions	**(9,284)**	(10,569)	(12)
Net capital expenditures	**$ 191,176**	$ 101,127	89

CASH DISTRIBUTIONS

Cash distributions for 2003 were $68.7 million, or $2.195 per Trust unit, compared with $37.8 million or $1.81 per Trust unit in 2002. During 2003, APF funded $9.3 million of capital expenditures from cash flow (2002 – $5.1 million), resulting in a payout ratio of 87% (2002 – 88%). For 2004, APF intends to maintain its historical policy of retaining a portion of available cash flow to fund capital expenditures and development initiatives, with a target range of 15% to 20%.

DISTRIBUTION REINVESTMENT PLAN

On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003. The DRIP allows eligible unitholders to direct that their monthly cash distributions be reinvested in additional Trust units at 95% of the average market price (as defined in the DRIP) on the applicable distribution date.

The DRIP includes a feature which allows eligible unitholders to elect, under the premium distribution component, to have these additional Trust units delivered to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such unitholders would have otherwise been entitled to receive on the applicable distribution date.

The DRIP also allows those unitholders who participate in either the distribution reinvestment component or the premium distribution component to purchase additional Trust units directly from APF for cash at a purchase price equal to the average market price (with no discount) in minimum amounts of $1,000 per remittance and up to $100,000 aggregate amount of remittances by a unitholder in any calendar month, all subject to an overall annual limit of 2% of the outstanding Trust units.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2003, APF had a revolving term credit facility in the amount of $150 million, with a borrowing base of $150 million, of which $98 million was drawn. The facility may be drawn down or repaid at any time, and there are no scheduled repayment terms.

On July 3, 2003, APF closed a $50.0 million 9.40% convertible unsecured subordinated debenture offering. At December 31, 2003, the balance of convertible debentures net of conversions was $48.8 million including accumulated interest of $2.3 million.

During the fourth quarter of 2003, $11.9 million (2002 - $7.6 million) was spent on development and optimization, $3.6 million (2002 - $23.5 million) on producing property acquisitions and $6.9 million (2002 - $0.8 million) was received for property dispositions.

At December 31, 2003, APF had a working capital deficit of approximately $10.2 million, compared with a working capital surplus of $0.4 million at December 31, 2002. The primary reasons for the working capital deficiency at December 31, 2003 are the significant increase in development drilling activity at December 31, 2003, resulting in higher capital expenditure accruals, along with the accrual for the STIP and provision for the semi-annual payment of debenture interest due January 31, 2004. Subsequent to year-end, APF raised $55.2 million through an equity issue and the proceeds were used to fund the working capital deficit and pay down long-term debt.

APF has budgeted the following amount for its capital program in 2004. Approximately 85% of the $40 million has been allocated for drilling and optimization initiatives.

2004 Estimated Capital Spending

Area	$ (millions)	% of Total
Central Alberta	$ 9.2	23
East Alberta/Heavy Oil	1.4	4
Southern Alberta	8.0	20
Southeast Saskatchewan	14.1	35
Coalbed Methane	7.3	18
Total	$ 40.0	100

The capital program will be funded through a combination of cash flow, distribution re-investment proceeds and debt, with a record 167 gross wells to be drilled for both conventional and coalbed methane ("CBM") opportunities.

CBM development is expected to result in the drilling of 63 gross wells in 2004. Canadian operations will focus on test wells at Doris and Timeu and completion of a 10-well pilot project in the Mannville coals at Corbett Creek. In the United States, development will continue on several projects in the Powder River Basin as APF looks to expand current operations.

UNITHOLDERS' EQUITY

At December 31, 2003, APF had 34.1 million Trust units outstanding (2002 – 22.9 million) and a market capitalization of approximately $427.1 million (2002 – $224.6 million).

In February, 2003, APF issued 4.0 million Trust units at $9.45 per Trust unit for the acquisition of Hawk Oil.

In April, 2003, APF issued 5.4 million Trust units at $10.40 per Trust unit for gross proceeds of $55.7 million. Proceeds from this issue were used to finance the purchase of Nycan and to reduce bank debt.

In June, 2003, APF issued 50,000, 9.4% convertible unsecured subordinated debentures for the acquisition of a 17% interest in Swan Hills Unit No. 1. APF signed a purchase and sale agreement with a third party, for 17% of the Unit for $91.8 million, that was subject to certain rights of first refusal ("ROFR") by another party. The party exercised the ROFR, which resulted in APF receiving 2.55% of the Unit for approximately $15.9 million. The remainder of the debenture issue was used to reduce bank debt and ultimately to partially fund the acquisition of CanScot in September.

In September, 2003, APF issued 1.3 million Trust units at $11.50 per Trust unit for the acquisition of CanScot.

In December, 2003, APF issued 140,710 Trust units pursuant to the new Premium Distribution Reinvestment Plan for proceeds of $1.60 million (2002 - $nil).

During 2003, 199,005 Trust units (2002 - 61,777) were issued pursuant to the Trust unit incentive plan for total proceeds of $1.8 million (2002 - $0.5 million). An additional 107,998 units were issued during the year upon conversion of debentures.

On February 4, 2004, APF closed the issue of 4.8 million Trust units at a price of $11.60 each for gross proceeds of $55.3 million. The proceeds of this offering were used to fund working capital and pay down debt.

Commitments and Contingencies

APF is involved in certain legal actions that occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

APF has compiled a capital budget that has been approved by the Board. The budget forecast is a best estimate of the projects that APF intends to undertake during the year, but does not constitute a legal or contractual obligation to do so. For properties that APF does not operate, a commitment to complete a project at a given future date may be required from the operator. As of the first quarter of 2004, APF has not committed any material funds for these projects.

(000)	2004	2005	2006	2007	2008
Lease commitments	$ 773	$ 756	$ 710	$ 706	$ 359

BUSINESS RISKS

APF is faced with a number of business risks that are inherent in the oil and gas industry and which can have an impact on distributions to unitholders. To mitigate these risks, APF follows appropriate policies and procedures in its ongoing operations and in its long-term strategic planning.

Financial and market risks associated with commodity prices and foreign currency exchange rates are mitigated through APF actively managing the sale of its own production to maximize price and through the use of a hedging program to hedge commodity prices and foreign currency rates with creditworthy counterparties. Hedging is employed as a risk management tool and not for speculation. APF entered into three interest rate swaps during 2003, which expire at various dates in 2005.

There are inherent operational risks associated with oil and natural gas production, relating to the ability to produce, process and transport oil and natural gas; the ability to replace production and maintain reserves and environmental and safety risks associated with well and production facilities. To mitigate these risks, APF employs a strategy of operating a significant portion of its production, thereby providing greater control over operations; APF employees and contractors adhere to APF's safety program and keep current on changes to operating practices, and APF maintains insurance coverage to minimize the impact of operational losses.

APF's ability to grow is dependent upon its ability to raise debt and equity capital in the Canadian capital markets. APF has lines of credit with three Canadian chartered banks that provide debt financing for acquisitions. The issue of new equity allows APF to pay down debt while continuing to make acquisitions. If Canadian debt or equity markets were to become inaccessible to APF, it may affect the ability of APF to continue to replace production and maintain distributions.

Changing government royalty regulations, income tax laws, incentive programs relating to the oil and gas industry and changes in securities legislation are all examples of regulatory changes that can affect APF's activities.

APF's cash flow is influenced by changes in a number of variables. Sensitivities to 2004 pre-hedging cash flows are as follows:

Variable	Change	Cash flow Impact ($000)	Change Per Unit
Crude oil price	$U.S. 1 per bbl	2,360	$0.07
Natural gas price	$Cdn. 0.10/mcf	1,200	$0.04
$U.S./$Cdn. exchange rate	$0.01	2,000	$0.06
Interest rate	1.00%	1,000	$0.03
Crude oil production	100 bbl/d	1,095	$0.03
Natural gas production	1 mmcf/d	1,500	$0.04

Critical Accounting Estimates

In order to prepare the financial statements in conformity with generally accepted accounting principles in Canada, APF has to make estimates and assumptions. The matters described below are considered to be the most critical in understanding the judgments that are involved in preparing the financial statements and the uncertainties that could impact the amounts reported on the results of operations, financial condition and cash flows. Accounting policies are described in Note 2 to the financial statements.

Estimation of oil and gas reserves

Oil and gas reserves have been estimated in accordance with National Instrument 51-101. Estimates of oil and gas reserves are inherently imprecise and represent only approximate amounts and are subject to future revision, as they are based on available reservoir data, prices and costs as of the date the estimate is made. Accordingly, the financial measures that are based on estimated reserves are also subject to change.

Depreciation, depletion and amortization

Proved reserves are used when calculating the unit-of-production rates used for depreciation, depletion and amortization for oil and gas assets including tangible fixed assets related to hydrocarbon production activities. The amount of depreciation is based on the units of production over the proved developed reserves of the relevant field during the time period. Unproved properties are amortized as required by particular circumstances. Other tangible fixed assets are generally depreciated on a straight-line basis over their estimated useful lives of five to ten years.

Ceiling test

The carrying amounts of fixed assets are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amounts for those properties may not be recoverable. If assets are determined to be impaired, the carrying amounts of those assets are written down to fair value. For this purpose, assets are assigned to a cost pool based on the country in which the activity has occurred. Estimates of future cash flows of assets related to hydrocarbon production activities are based on proved reserves determined in accordance with National Instrument 51-101.

Decommissioning and restoration costs

Provisions are held for the future decommissioning and restoration of oil and natural gas production facilities and pipelines at the end of their economic lives. Estimated decommissioning and restoration costs are based on current requirements, technology and price levels. Most of these obligations are many years in the future and the precise requirements that will have to be met are uncertain because technologies and costs as well as political, environmental, and safety expectations are subject to change.

RECENT ACCOUNTING AND REGULATORY GUIDELINE CHANGES

Full Cost Accounting Guideline

In September, 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost" to replace CICA Accounting Guideline 5. The new guideline proposes amendments to the ceiling test; as well, it requires additional disclosures relating to critical accounting estimates for impairment and depletion, depreciation and amortization.

The new guideline is effective for fiscal years beginning on or after January 1, 2004; however, APF has elected to adopt the standard early at December 31, 2003. There are no material financial impacts resulting from the adoption of this standard.

Asset Retirement Obligations

The Canadian Institute of Chartered Accountants ("CICA") issued Section 3110 "Asset Retirement Obligations" in March, 2003. The new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements. The Canadian standard will be effective for fiscal years beginning on or after January 1, 2004.

Under this standard, these obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over the life of the assets.

APF is currently evaluating the impact of this new standard and will adopt it during the first quarter of 2004.

Hedging Relationships

In December, 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003.

The new guideline addresses hedging transactions for the purposes of applying hedge accounting and establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue hedge accounting for positions hedged with derivatives.

A large portion of APF's current crude oil portfolio is a light sour or medium crude priced at Cromer and currently does not qualify as effective against the WTI light sweet crude price that APF currently hedges. As a result, APF does not anticipate applying hedge accounting against its existing crude oil hedge contracts.

In order for the currency hedge to qualify as effective, it must be associated with either U.S. denominated debt or U.S. denominated revenues. At December 31, 2003, APF did not have any U.S. denominated debt and the settlement terms for the foreign currency hedge is not aligned to the settlement dates of the WTI contracts. As a result, APF does not anticipate applying hedge accounting against its foreign currency hedge contracts.

The majority of APF's gas hedges are priced at AECO, which do correlate with existing gas revenue streams. APF is evaluating the impact of the standard with respect to gas contracts, and expects to finalize its decision to apply hedge accounting in the first quarter of 2004.

Variable Interest Entities

In June, 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. APF is assessing the impact of this new guideline.

Continuous Disclosure Rules

Effective March 30, 2004, all reporting issuers in Canada were to be subject to new continuous disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective, generally, for fiscal years beginning on or after January 1, 2004. The Instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and the Annual Information Form ("AIF").

The Instrument also proposes enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for APF to mail annual and interim financial statements and MD&A to unitholders, but rather, these documents are to be provided on an "as requested" basis. APF continues to assess the implications of this new instrument, which will be implemented at March 30, 2004.

Accounting for Convertible Debentures

In June, 2003, the CICA approved an amendment to Handbook section 3860 "Financial Instruments – Disclosure and Presentation". Under the previous guidelines, debt obligations that could be settled with the entity's own equity instruments could be classified as equity, and related interest was treated as a reduction of unitholders' equity.

The amendment would require certain obligations that must or could be settled with an entity's own equity instruments to be presented as a liability, with the corresponding interest being booked through the income statement. The amendment is effective for all fiscal years starting after November 1, 2004.

Outlook

APF remains committed to its strategy of buying well and exploiting its land base through development drilling, recompletions and field optimizations. For 2004, a total of 167 gross wells have been budgeted for drilling. APF has allocated $40 million to its capital expenditure budget for the year with 85% of the funds being directed to drilling and development of conventional properties. Throughout 2004, APF will continue to expand its CBM pilot projects in Central Alberta. In total, $7 million has been identified in the capital budget for CBM initiatives in both Canada and the U.S. With low production declines and the potential for higher rates of return than conventional production, APF feels CBM presents a very attractive opportunity and is ideally suited for the trust structure.

APF will continue to pursue acquisitions that will be accretive on a per unit basis to cash flow, production, reserves and net asset value. APF is committed to maintaining stable cash distributions over the long-term. In order to mitigate the commodity price risk that is inherent to the oil and gas sector, APF will continue to actively hedge production. APF believes that over the long term, outlook for both crude oil and natural gas pricing remains strong.

DISCLAIMER

Certain statements in this document are "forward-looking statements" including outlook on oil and gas prices, royalty rates, operating expenses, estimates of future production, estimated completion dates of construction and development projects, business plans for drilling and exploration, estimated amounts and timing of capital expenditures and anticipated future debt levels. Information concerning reserves contained in this material may also be deemed to be forward-looking statements as such estimates involving 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 Energy Trust and APF Energy Inc. These risks include, but are not limited to: the risks of the oil and gas industry (e.g., operational risks in exploration for; development and production of crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; and health, safety and environmental risks); risks in conducting foreign operations (e.g., political and fiscal instability in nations where APF Energy does business); the possibility that government policies may change or governmental approvals may be delayed or withheld; and price and exchange rate fluctuations. These and other risks are described in APF Energy's reports that are on file with Canadian securities regulatory authorities. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors and management's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to APF or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. APF assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the consolidated financial statements and the preparation of all other financial information included in the annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, and where applicable, amounts based on management's best estimates and judgment.

Management has established procedures and systems of internal control designed to provide reasonable assurance that assets are safeguarded and that accurate financial information is produced in a timely manner.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and, through its Audit Committee, ensuring that management fulfills its responsibilities for financial reporting. The Audit Committee meets periodically with management and the external auditors to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors. PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, appointed by the unitholders of APF Energy Trust, have audited the consolidated financial statements in accordance with Canadian generally accepted auditing standards. PricewaterhouseCoopers LLP have full and free access to the Audit Committee.

Martin Hislop
Chief Executive Officer

Alan MacDonald
Vice President, Finance

Calgary, Alberta
February 20, 2004

Auditors' Report

To the Unitholders of APF Energy Trust

We have audited the consolidated balance sheets of APF Energy Trust as at December 31, 2003 and 2002 and the consolidated statements of operations and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust'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 Trust 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.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta
February 20, 2004

Consolidated Balance Sheets

As at December 31	2003	2002
	($000)	($000)
ASSETS		
Current assets		
Cash	**1,381**	950
Accounts receivable	**27,542**	21,111
Other current assets	**3,506**	2,779
	32,429	24,840
Site restoration fund (note 6)	**2,342**	784
Goodwill (note 7)	**48,230**	11,476
Property, plant and equipment (note 5)	**401,286**	260,527
	484,287	297,627
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**36,711**	16,943
Due to APF Energy Management Inc. (note 14)	**–**	3,923
Cash distribution payable	**5,963**	3,565
	42,674	24,431
Future income taxes (note 13)	**64,222**	39,625
Long-term debt (note 8)	**98,000**	88,000
Site restoration liability (note 6)	**10,410**	6,227
	215,306	158,283
UNITHOLDERS' EQUITY		
Unitholders' investment account (note 9)	**324,317**	214,405
Contributed surplus (note 10)	**1,241**	–
Accumulated earnings	**78,637**	35,589
Accumulated cash distributions (note 4)	**(179,363)**	(110,650)
Convertible debentures (note 12)	**46,466**	–
Accumulated interest on convertible debentures	**(2,317)**	–
	268,981	139,344
	484,287	297,627

Contingencies and commitments (note 17)

See accompanying notes to consolidated financial statements

Approved by the Board of Directors

Don Engle
Director

Martin Hislop
Director

Consolidated Statements of Operations and Accumulated Earnings

For the years ended December 31	**2003**	2002
	($000)	($000)
Revenue		
Oil and gas	**163,532**	92,345
Royalties expense, net of ARTC	**(32,473)**	(18,707)
Other	**1,925**	1,676
	132,984	75,314
Expenses		
Operating	**32,370**	19,748
General and administrative (note 14)	**10,023**	4,635
Stock-based compensation expense (note 10)	**1,241**	–
Management fee (note 14)	**–**	1,976
Interest on long-term debt	**4,171**	2,834
Depletion, depreciation and amortization	**50,417**	30,201
Site restoration	**3,327**	2,087
Capital and other taxes	**2,720**	1,901
Internalization of management contract (note 14)	**–**	7,297
	104,269	70,679
Income before income taxes and minority interest	**28,715**	4,635
Recovery of future income taxes (note 13)	**14,333**	7,133
Income before minority interest	**43,048**	11,768
Minority interest (note 14)	**–**	403
Net income	**43,048**	11,365
Accumulated earnings – beginning of year	**35,589**	24,224
Accumulated earnings – end of year	**78,637**	35,589
Net income per unit – basic ($)	**1.32**	0.55
Net income per unit – diluted ($)	**1.21**	0.55

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

For the years ended December 31	2003	2002
	($000)	($000)
CASH PROVIDED BY (USED IN)		
Operating activities		
Net income for the year	**43,048**	11,365
Items not affecting cash		
Depletion, depreciation and amortization	**50,417**	30,200
Minority interest	**–**	403
Future income taxes	**(14,333)**	(7,133)
Internalization of management contract	**–**	7,037
Stock-based compensation expense	**1,241**	–
Site restoration	**3,327**	2,087
Site restoration expenditures (note 6)	**(374)**	(171)
	83,326	43,788
Net change in non-cash working capital items		
Accounts receivable	**1,016**	(7,994)
Other current assets	**(398)**	(328)
Accounts payable and accrued liabilities	**9,138**	6,537
Due to related party / APF Management	**(3,923)**	(1,088)
Cash distribution payable	**2,398**	1,227
	8,231	(1,646)
Site restoration fund contribution	**(1,558)**	(754)
Cash distributions	**(68,713)**	(37,766)
	21,286	3,622
Investing activities		
Purchase of Hawk Oil	**(3,456)**	–
Purchase of Nycan Energy	**(34,287)**	–
Purchase of CanScot Resources	**(20,516)**	–
Purchase of Kinwest	**–**	(17,361)
Additions to property, plant and equipment	**(33,601)**	(20,979)
Purchase of oil and natural gas properties	**(29,238)**	(28,574)
Proceeds on sale of properties	**9,284**	10,569
Changes in non-cash working capital-investing items	**2,961**	(560)
	(108,853)	(56,905)
Financing activities		
Issue of units for cash	**57,272**	32,250
Issue of units for cash upon exercise of stock options	**1,749**	554
Unit issue costs	**(3,467)**	(1,861)
Convertible debentures – net of costs	**47,681**	–
Interest on convertible debentures	**(2,317)**	–
(Repayment)/proceeds on issue of long-term debt – net	**(12,920)**	21,650
Distribution to 1% minority interest	**–**	(403)
	87,998	52,190
Change in cash during the year	**431**	(1,093)
Cash – beginning of year	**950**	2,043
Cash – end of year	**1,381**	950

Supplemental information (note 16)

See accompanying notes to consolidated financial statements

The objective and integrity of data in these financial statements, including estimates and judgements relating to matters not concluded by year-end, are the responsibility of management of APF Energy Trust ("Trust"). In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies.

NOTE 1 BASIS OF PRESENTATION

APF Energy Trust (the "Trust")
The Trust is an open-end investment trust under the laws of the Province of Alberta.

APF Energy Inc. ("Energy")
Energy was incorporated and organized for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties, including certain initial properties and granting a royalty thereon to the Trust.

APF Energy Limited Partnership ("LP")
LP was formed for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties and granting a royalty thereon to the Trust.

Tika Energy Inc. ("Tika")
Tika is a wholly owned subsidiary of Energy and was incorporated in Wyoming for the purpose of acquiring, developing, exploiting and disposing of coalbed methane gas properties in the United States.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Consolidation
These consolidated financial statements include the accounts of the Trust, Energy, LP and Tika and are referred to collectively as "APF".

Revenue recognition
Revenue associated with the sale of crude oil, natural gas, and natural gas liquids owned by the Trust are recognized when title passes from the Trust to its customers.

Goodwill
The Trust records goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or as events occur that could indicate an impairment. Impairment is recognized based on the fair value of APF compared to the net book value of APF. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Property, plant and equipment – oil and natural gas
APF follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in a cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements, which extend the economic life of the property, plant and equipment are capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more.

Ceiling test
The Trust places a limit on the aggregate carrying value of property, plant and equipment. An impairment is recognized if the carrying amount of the property, plant and equipment exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

The Trust determines if there is an impairment by comparing the carrying amounts of the property, plant and equipment to an amount equal to the fair value of the property, plant and equipment. Any excess carrying value above the fair value of the Trust's future cash flows would be recorded as a permanent impairment. The cost of unproved properties are excluded from the ceiling test calculation and is subject to a separate impairment test.

Depletion, depreciation and amortization

Depletion, depreciation and amortization of oil and natural gas assets including tangible equipment is calculated using the unit-of-production method based on the working interest share of total proven reserves before royalties. Reserves estimates are calculated in accordance with National Instrument 51-101 and relative volumes of petroleum and natural gas reserves and production, before royalties are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Site restoration and abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method. Actual site restoration costs are charged against the accumulated provision.

Other equipment

All other equipment is carried at cost and is depreciated over the estimated useful life of the assets at annual rates varying from 10% to 30%.

Joint ventures

Substantially all oil and natural gas production and exploitation activities are conducted jointly with others. Accordingly, the accounts reflect APF's proportionate interest in these activities.

Trust per unit calculations

The Trust has applied the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

Cash distributions declared per unit amount are based on actual distribution for units outstanding at the time of declaration.

Unit based compensation

APF has established a Trust Unit Incentive Rights Plan (the "Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of APF. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to unitholders to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the financial statements for unexercised rights.

The Trust has a Trust Unit Incentive Rights Plan which is described in note 10.

Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in earnings in the period of change with a corresponding increase or decrease in contributed surplus. This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying Trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights exercised or outstanding at the date of the financial statements.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital. If Trust Units or Trust Unit options are repurchased from employees, the excess of the consideration paid over the carrying amount of the Trust Units or Trust Unit options cancelled is charged to accumulated earnings.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, APF accounts for actual forfeitures as they occur.

Cash distributions
Cash distributions are calculated on an accrual basis and are paid to the Unitholders based upon funds available for distribution.

Income taxes
The Trust is an inter vivos trust for income tax purposes. As such, the Trust is taxable on any taxable income which is not allocated to the Unitholders. The Trust intends to allocate all taxable income to Unitholders. Should the Trust incur any income taxes, the funds available for distribution will be reduced accordingly. Provision for income taxes is recorded in Energy at applicable statutory rates. Provision for income taxes is recorded in Energy using the liability method of accounting whereby the future income tax effect of any difference between the accounting and income tax basis of an asset or liability is booked.

Management estimates
The consolidated financial statements include certain management estimates that may require accounting adjustments based on future occurrences. The most significant estimates relate to depletion, depreciation and amortization and ceiling test calculations for capital assets including future abandonment liabilities as they are based on engineering reserve estimates and estimated future costs.

NOTE 3 CHANGE IN ACCOUNTING POLICIES

Accounting Guideline 16
Effective December 2003, the Trust adopted AcG-16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants which replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry".

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

Stock based compensation
APF elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, APF must account for compensation expense based on the fair value of rights granted under its' unit-based compensation plan. As APF is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the grant date or at the date of the financial statements for unexercised rights as described in Note 2.

For rights granted in 2002, APF has elected to disclose pro forma results as if the amended accounting standard had been adopted retroactively. As a result of adopting this standard, net income for the year ended December 31, 2003 decreased by $1.2 million and contributed surplus increased by $1.2 million.

See Note 10 for additional information regarding the nature of the plan and the associated compensation expense.

NOTE 4 CASH DISTRIBUTIONS AND ACCUMULATED CASH DISTRIBUTIONS

The following table is the calculation of cash distributions and accumulated cash distributions:

($000, except per unit amounts)	2003	2002
	$000	$000
Oil and gas sales	163,532	92,345
Other	1,925	1,676
Gross overriding royalties and lessors' royalties	(13,109)	(7,802)
	152,348	86,219
Less		
Operating costs	32,370	19,748
General and administrative	9,362	4,317
Management fees	–	1,976
Debt service charges (including interest and principal)	4,171	2,834
Site restoration fund contribution	1,932	925
Capital and other taxes	2,720	1,901
Capital expenditures funded from cash flow	9,326	5,144
	59,881	36,845
Income subject to the royalty	92,467	49,374
99% of income subject to the royalty	91,542	48,880
Crown charges, net of Alberta Royalty Tax Credit	(19,851)	(10,796)
Interest on convertible debentures	(2,317)	–
General and administrative costs of the Trust	(661)	(318)
Cash available to be distributed	68,713	37,766
Cash distributed to date	62,750	34,201
Cash distribution payable	5,963	3,565
Actual cash distribution declared per unit ($)	2.195	1.810
Opening accumulated cash distributions	110,650	72,884
Distribution declared and paid	62,750	34,201
Distribution declared and payable	5,963	3,565
Closing accumulated cash distributions	179,363	110,650

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

($000)	2003	2002
Property, plant and equipment	531,365	340,189
Accumulated depletion, depreciation and amortization	(130,079)	(79,662)
	401,286	260,527

The calculation of 2003 depletion, depreciation and amortization included an estimated $25.0 million (2002 – $16.7 million) for future development costs associated with proved undeveloped reserves and excluded $10.8 million (2002 – $7.9 million) for the estimated value of unproved properties and coalbed methane projects currently in the development stage. General and administration costs of $458,000 associated with coalbed methane projects have been capitalized (2002 – $nil).

The Trust performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of property, plant and equipment. The crude oil and natural gas futures prices are management's best estimates and are based on information obtained from third parties and were adjusted for commodity differentials specific to the Trust. Future prices were obtained for the period of 2004 to 2008 inclusive and then escalated based on escalation factors in the Trust's year-end independent reserves evaluation.

Based on these assumptions, which are shown below, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's property, plant and equipment at December 31, 2003.

Year	WTI Oil ($U.S./bbl)	Foreign exchange rate ($U.S./$Cdn.)	WTI Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2004	30.18	0.77	39.43	5.72
2005	27.44	0.76	36.12	5.42
2006	26.67	0.75	35.33	5.27
2007	26.61	0.75	35.43	5.23
2008	26.78	0.75	35.77	5.18
2009 – 2014 (1)	–			–
Remainder (2)	1.5%			1.5%

(1) Percentage change represents the average for the period noted.

(2) Percentage change represents the change in each year after 2014 to the end of the reserve life.

NOTE 6 SITE RESTORATION FUND/LIABILITY

Energy and the LP are responsible for future site restoration costs on all properties. At December 31, 2003 the future undiscounted estimated costs for the site restoration liabilities were $31,198,000 (2002 – $29,858,000), of which $10,410,000 has been provided for. The current year expense charged to the provision was $3,327,000 (2002 – $2,087,000). Actual payments for abandonment in 2003 were $374,000 (2002 – $171,000).

A site restoration fund was established to fund future site reclamation and abandonment costs. Contributions to the site restoration fund during the year totalled $1,932,000 (2002 – $925,000) and have been deducted in calculating the income subject to the royalty.

Contributions to the site restoration fund are determined annually by management and are based on the average of the next three years expected site restoration expenses, as determined by the independent engineers.

NOTE 7 ACQUISITIONS

Effective February 5, 2003, Energy acquired all of the issued and outstanding shares of Hawk Oil Inc. ("Hawk Oil"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Bank overdraft	(5)
Other working capital	(629)
Property, plant and equipment	57,146
Goodwill	11,078
Debt assumed	(7,900)
Site restoration liability	(263)
Future income taxes	(18,266)
Total net assets acquired	41,161
Financed by	
Cash	2,856
Trust units issued (3,990,461 Trust units)	37,710
Acquisition costs	595
Total consideration	41,161

Effective April 28, 2003, Energy acquired all of the issued and outstanding shares of Nycan Energy Corp. ("Nycan"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Cash	212
Other working capital	716
Property, plant and equipment	47,495
Goodwill	8,792
Debt assumed	(8,870)
Site restoration liability	(580)
Future income taxes	(13,266)
Total net assets acquired	34,499
Financed by	
Bank debt	34,374
Acquisition costs	125
Total consideration	34,499

Effective September 26, 2003, Energy acquired all of the issued and outstanding shares of CanScot Resources Ltd. ("CanScot"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Cash	156
Other working capital	22
Property, plant and equipment	32,980
Goodwill	16,884
Debt assumed	(6,150)
Site restoration liability	(388)
Future income taxes	(7,399)
Total net assets acquired	36,105
Financed by	
Bank debt	19,689
Trust units issued (1,342,004 Trust units)	15,433
Acquisition costs	983
Total consideration	36,105

Effective May 30, 2002, Energy acquired all of the issued and outstanding shares of two private corporations, Kinwest Energy Inc. ("Kinwest") and Kinwest's joint venture partner (collectively the "Kinwest Acquisition"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Working capital	1,641
Property, plant and equipment	63,483
Goodwill	11,476
Debt assumed	(10,146)
Site restoration liability	(673)
Future income taxes	(15,410)
Total net assets acquired	50,371
Financed by	
Cash	13,042
Trust units issued (3,385,510 Trust units)	36,056
Acquisition cost – due to related party	838
Acquisition costs	435
Total consideration	50,371

NOTE 8 LONG-TERM DEBT

($000)	2003	2002
Bank loans	**98,000**	88,000

At December 31, 2003, APF had a $150.0 million revolving term credit facility with a syndicate of Canadian resident financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The debt bears interest based on a sliding scale tied to APF's debt to cash flow ratio, from a minimum of the bank's prime rate plus 0.125% to a maximum of the prime rate plus 1.625% (2002 – prime rate plus 1.5%) or where available, at Banker's Acceptances rates plus a stamping fee of 1.125% to 2.0% (2002 – 1.125% to 2.5%). The debt is secured by a $300.0 million demand debenture containing a first fixed charge on all the petroleum and natural gas assets of APF and an assignment of book debts and material gas contracts. At December 31, 2003, the interest rate was bank prime of 4.5% plus 0.125% (2002 – 4.5% plus 0.25%).

APF has the option to extend the revolving period for an additional 364 days by giving notice to the lenders no earlier than 180 days and no less than 90 days prior to the end of the revolving period. If the revolving period is not extended, the outstanding principal will be converted to a one-year non-revolving term loan commencing on the day immediately following the end of the then current revolving period. During the one-year term period, APF will pay 1/6th of the outstanding principal on the 180th day after the commencement of the one-year term period and 1/12th of the outstanding principal on the 90th day thereafter.

NOTE 9 UNITHOLDERS' INVESTMENT ACCOUNT

	2003		2002	
		Amounts		Amounts
	Units	($000)	Units	($000)
Balance – Beginning of year	**22,942,417**	**214,405**	15,583,880	141,069
Issued to acquire Hawk Oil	**3,990,461**	**37,710**	–	–
Issued to acquire CanScot Resources	**1,342,004**	**15,433**	–	–
Issued to acquire Kinwest	**–**	**–**	3,385,510	36,056
Issued for cash	**5,351,645**	**55,670**	3,303,665	32,250
Cost of units issued	**–**	**(3,467)**	–	(1,861)
Distribution reinvestment program	**140,710**	**1,602**	–	–
Issued on conversion of debentures	**107,998**	**1,215**	–	–
Issued under management internalization	**–**	**–**	608,185	6,337
Issued on exercise of options/rights	**199,005**	**1,749**	61,177	554
Balance – End of year	**34,074,240**	**324,317**	22,942,417	214,405

The holders of Units are entitled to vote at any meeting of the Unitholders.

The per unit calculations are based on the weighted average number of units outstanding during the year of 30,970,093 units (2002 – 20,470,210 units). In computing diluted net income per unit, 334,077 units were added to the weighted average number of units outstanding during the year (2002 – 57,569) for the dilutive effect of employee options and rights to acquire Trust units. In addition, 4,336,444 units were added (2002 – nil) for the dilutive effect of the convertible debentures for a total weighted average number of units for 2003 of 35,640,614 (2002 – 20,527,779).

Net income for 2003 has been adjusted by $2,317,000 (2002 – $nil) for the interest accrued on the convertible debenture for purposes of calculating basic earnings per unit.

In 1999, the Trust created a Unitholders' Rights Plan and authorized the issuance of one right in respect of each Unit outstanding. Each right would allow Unitholders in specified circumstances, to acquire, on payment of an exercise price of $50.00, the number of Units having an aggregate market price equal to twice the exercise price of the rights.

Effective with the December 2003 distribution, the Trust initiated a premium distribution reinvestment plan ("DRIP"). The DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95% of the average market price as defined in the plan ("Regular DRIP").

The premium distribution component permits eligible unitholders to elect to receive 102% of the cash the unitholder would otherwise have received on the distribution date ("Premium DRIP"). Participation in the Regular DRIP and Premium DRIP is subject to proration by the Trust. Unitholders who participate in either the Regular DRIP or the Premium DRIP are also eligible to participate in the optional unit purchase plan as defined in the DRIP.

NOTE 10 TRUST UNIT INCENTIVE RIGHTS PLAN

Pursuant to a Trust Unit Incentive Plan dated December 17, 1996 and amended February 1, 1998 (the "Plan"), employees, directors and long-term consultants may be granted options to acquire Units of the Trust. The exercise price for each option was the market price of the Units at the time the option was granted. Options granted prior to February 1, 1998 vested immediately, while options granted on or after February 1, 1998 vest in one-third increments on the first, second and third anniversaries of their grant. The maximum term for options is five years. This Plan was terminated in 2001 and replaced with a new Trust Unit Incentive Rights Plan ("Rights Plan").

Under the Rights Plan, employees, directors and long-term consultants may be granted rights to purchase Units of the Trust. The initial exercise price of rights granted under the Rights Plan may not be less than the current market price of the Trust Units as of the date of the grant and the maximum term of each right is not to exceed ten years. The exercise price is to be adjusted downwards from time to time by the amount, if any, that distributions to Unitholders in any calendar quarter exceed a percentage of APF's net book value of property, plant and equipment, as determined by the Trust.

APF recorded compensation expense and contributed surplus of $1,241,000 for rights issued in 2003, based on the year-end unit price of $12.54.

For rights granted in 2002, APF has elected to disclose proforma results as if the amended accounting standard has been applied retroactively. For the year ended December 31, 2003, APF's net income would have decreased by $950,000 for the estimated compensation cost associated with rights granted under the plan between January 1 and December 31, 2002 as follows:

($000)	**2003**	2002
Net income as reported	**43,048**	11,365
Less: Compensation expense for rights issued in 2002	**(950)**	–
Pro forma net income	**42,098**	11,365
Basic net income per Trust unit		
As reported	**1.32**	0.55
Proforma	**1.28**	0.55
Diluted net income per Trust unit		
As reported	**1.21**	0.55
Proforma	**1.18**	0.55

No compensation expense has been recorded for 2002 as the adjusted exercise price of the rights exceeded APF's market price at December 31, 2002.

Net income in the basic per Trust unit calculation has been reduced by interest on the convertible debentures of $2.3 million for purposes of calculating the basic net income.

NOTE 11 RIGHTS AND OPTIONS OUTSTANDING

A summary of the status of the Plan as of December 31, 2003 and 2002 is as follows:

Trust Unit Options	**Units**	**2003 Weighted average price ($)**	Units	2002 Weighted average price ($)
Outstanding – beginning of year	**244,029**	**9.13**	330,540	9.32
Granted	**–**	**–**	–	–
Exercised	**(106,786)**	**8.55**	(58,677)	9.05
Forfeited	**(10,774)**	**9.42**	(27,834)	11.62
Outstanding – end of year	**126,469**	**9.59**	244,029	9.13
Options exercisable – end of year	**60,173**	**9.48**	76,488	8.72

The following table summarizes options information under the Plan outstanding at December 31, 2003:

Range of Exercise prices ($)	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price ($)	Number exercisable December 31, 2003	Weighted average price ($)
7.00 – 7.99	700	1.18	7.15	700	7.15
8.00 – 9.00	6,899	0.15	8.00	6,899	8.00
9.01 – 10.00	118,870	2.17	9.70	52,574	9.70
	126,469	2.10	9.59	60,173	9.48

Rights plan

During the year, the Trust granted 1,538,250 rights (2002 – 441,233) under the Rights Plan to employees and directors to purchase Trust units at prices ranging from $9.67 to $11.54 (2002 – $9.73 to $10.80) per Trust unit.

A summary of the Rights Plan at December 31, 2003 and 2002 is as follows:

	2003 Number of rights	**2003 Weighted average price ($)**	2002 Number of rights	2002 Weighted average price ($)
Balance – beginning of year	**429,333**	**9.37**	–	–
Granted	**1,538,250**	**9.78**	441,233	9.86
Exercised	**(92,219)**	**9.05**	(2,500)	9.73
Cancelled	**(51,034)**	**9.67**	(9,400)	9.73
Balance before reduction of exercise price	**1,824,330**	**9.72**	429,333	9.86
Reduction of exercise price	**–**	**0.63**	–	0.49
Balance – end of year	**1,824,330**	**9.09**	429,333	9.37
Rights exercisable – end of year	**47,221**	**8.58**	–	–

The following table summarizes information about the Rights Plan as at December 31, 2003:

Range of Exercise prices ($)	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price ($)	Number exercisable December 31, 2003	Weighted average price ($)
8.00 – 9.00	222,180	8.17	8.40	40,721	8.49
9.01 – 10.00	1,508,623	9.27	9.06	6,500	9.18
10.01 – 11.00	10,858	9.45	10.45	–	–
11.01 – 12.00	82,669	9.50	11.31	–	–
	1,824,330		9.09	47,221	8.58

NOTE 12 CONVERTIBLE DEBENTURES

On July 3, 2003, APF issued $50.0 million of unsecured subordinated convertible debentures ($47.7 million net of issue costs) with a 9.40% coupon rate maturing July 31, 2008. Interest is paid semi-annually on January 31 and July 31. The debentures may be converted into Trust units at the option of the holder at a conversion price of $11.25 per Trust unit prior to July 31, 2008 and may be redeemed by APF under certain circumstances. The debentures and related interest obligations have been classified as equity on the consolidated balance sheet as APF may elect to satisfy interest and principal obligations by the issuance of Trust units. During the year, $1.2 million of convertible debentures were converted into 107,998 Trust units.

NOTE 13 INCOME TAXES

Energy and the LP have approximately $70.0 million of unused tax pools at December 31, 2003 ($60.4 million – December 31, 2002) available to be used to offset future taxable income subject to certain restrictions of the Income Tax Act.

Energy had approximately $22.3 million in non-capital losses at December 31, 2003 ($15.3 million – December 31, 2002) of which approximately $945,000 expire in 2005 and the remainder through 2010.

The Unitholders are responsible for their own income taxes. Distributions will be a combination of taxable income and a return of capital in the year received. Generally, when the Trust has no taxable income prior to the deduction of distributions, distributions will not be taxable but will be a return of capital which reduces the Unitholders' adjusted cost base in those years.

Distributions paid are deducted from taxable income only to the extent needed to reduce taxable income in the Trust to zero. Generally, the distributions deducted for the Trust tax return are taxable income to the Unitholders.

($000)	2003	2002
Income before income taxes	**28,715**	4,635
Statutory tax rate	**42.75%**	43.5%
Expected tax provision	**12,276**	2,016
Effect on income tax of		
Net income of the Trust	**(21,002)**	(12,603)
Resource allowance	**(2,250)**	(595)
Non-deductible crown charges	**669**	47
Internalization of management contract	**–**	3,174
Capital tax	**1,163**	827
Rate reduction	**(3,717)**	–
Other	**(1,472)**	–
Provision for future income taxes	**(14,333)**	(7,134)
The future tax recorded on the balance sheet results from		
Capital assets in excess of tax value	**72,725**	46,282
Future tax losses that are likely to be utilized	**(8,503)**	(6,657)
	64,222	39,625

Taxable income of the Trust is comprised of income from royalty, adjusted for crown royalties and resource allowance, less deductions for Canadian oil and natural gas property expense (COGPE), which is claimed at a rate of 10% on a declining balance basis and issue costs which are claimed at 20% per year on a straight-line basis. Any losses that occur in the Trust must be retained in the Trust and may be carried forward and deducted from taxable income for a period of seven years. The COGPE during 2003 resulted from the purchase of royalty interests.

The amount of COGPE and issue costs remaining in the Trust are approximately $122.3 million.

NOTE 14 RELATED PARTY TRANSACTIONS

Internalization of management

On December 18, 2002, Unitholders approved the acquisition of APF Energy Management Inc. (the "Manager"), effective January 1, 2003. Total consideration for the transaction consisted of a cash payment of $3.9 million and the issuance of 608,185 Trust Units to the shareholders of the Manager as detailed below:

($000)	
Net assets acquired	
Cash	419
Working capital	629
Property, plant and equipment	4,512
Future income taxes	(1,917)
Internalization of management contract	7,297
Total net assets acquired	10,940
Total consideration	
Cash	3,923
Trust units issued	6,337
Transaction costs	680
Total purchase price	10,940

Although the transaction did not close until January 3, 2003, all of the major conditions, including unitholder and regulatory approval, had been obtained by December 31, 2002. Accordingly, the transaction was accounted for as if it had closed on December 31, 2002.

The consideration paid through the issue of Trust Units is partially subject to escrow restrictions. In the case of Mr. Martin Hislop, Chief Executive Officer, 100% of the 150,526 Trust Units issued are subject to escrow for 3 years, released as to one third on each anniversary date of the transaction. In the case of Mr. Cloutier, President and Chief Operating Officer, 80% of the 125,590 Trust Units issued are subject to escrow for 4 years, released as to one quarter on each anniversary date of the transaction. The remaining Trust Units issued to non-management shareholders of the Manager were not subject to escrow restrictions. Retention bonuses paid by the Manager to three other officers were used to subscribe for 53,665 Trust Units at a price of $10.482 per Trust Unit at closing. These Trust Units are subject to the same escrow restrictions as those Trust Units issued to the President.

Prior to the acquisition, APF paid fees to the Manager equal to 3.5% of net production revenue, structuring fees of 1.5% on the purchase price of acquisitions and dispositions, as well as the right to the residual 1% royalty. The internalization resulted in the elimination of all such fees under the management agreement.

Management contract

Prior to the internalization of the management contract, the Manager handled the business of APF pursuant to a management agreement. Fees payable to Management for management, advisory and administrative services included a fee equal to 3.5% of Net Production Revenue and structuring fees of 1.5% on both the purchase price of acquisitions and on the net proceeds of dispositions. In 2003, fees paid or payable to Management on Net Production Revenues were $nil (2002 – $1,976,000) and structuring fees were $nil (2002 – $1,022,000). During 2002 structuring fees were accounted for as either part of the purchase price or as a reduction of the proceeds of disposition of oil and natural gas properties.

During the year, Energy reimbursed Management $nil (2002 – $2,294,000) for general and administrative expenses. During 2002, Energy also acquired certain non-oil and gas business assets from Management for $850,000.

During 2002, Management, through its ownership of 100% of the shares of APF, was entitled to receive 1% of the royalty income derived from the Properties. The 1% minority interest is included as an expense in the consolidated statement of operations totalling $403,000 for 2002.

NOTE 15 FINANCIAL INSTRUMENTS

APF is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Derivative instruments are used by APF to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity.

The fair values of financial instruments that are included in the balance sheet, including long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments and the floating prime rate applied to long-term borrowings.

A substantial portion of APF's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

APF has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. APF sells forward a portion of its future production through commodity swap agreements with counterparties. The following contracts were outstanding as at December 31, 2003. The estimated market value at December 31, 2003, had the contracts been settled at that time, would have resulted in a reduction of revenues otherwise to be received of $400,000.

Term	Commodity	Type of contract	Average daily quantity	Average contract price	Price index
Jan. to Mar. 2004	Crude oil	Fixed price	3,167 bbls	$U.S. 29.63	WTI
Jan. to Mar. 2004	Natural gas	Fixed price	10,000 GJ	$Cdn. 7.19	AECO
Jan. to Mar. 2004	Natural gas	Fixed price	2,000 mmbtu	$U.S. 7.00	NYMEX
Apr. to Jun. 2004	Crude oil	Fixed price	1,833 bbls	$U.S. 30.05	WTI
Jul. to Sept. 2004	Crude oil	Fixed price	1,167 bbls	$U.S. 28.86	WTI

At December 31, 2003, APF had fixed the interest rate on a portion of its debt as follows:

Term	Amount ($000)	Interest rate
January 2004 to February 2005	$20,000	3.67% plus stamping fee
January 2004 to May 2005	$20,000	3.75% plus stamping fee
January 2004 to November 2005	$20,000	3.58% plus stamping fee

The estimated market value of these interest rate contracts at December 31, 2003, had they been settled at that time, would be a cost of $900,000.

At December 31, 2003, APF had entered into the following foreign currency forward contract:

Term	Amount ($000)	Exchange rate ($Cdn./$U.S.)
January 2004 to December 2004	$U.S. 10,000	1.333

The estimated market value of these foreign currency forward contracts at December 31, 2003, had they been settled at that time, would be $nil.

NOTE 16 SUPPLEMENTAL INFORMATION FOR THE STATEMENTS OF CASH FLOWS

($000)	**2003**	2002
Cash payments related to certain items		
Interest	**4,070**	2,843
Interest on debentures	**30**	–
Distributions to minority interests	**-**	415
Distributions to Unitholders	**66,315**	36,539
Capital taxes	**3,389**	2,165

NOTE 17 CONTINGENCIES AND COMMITMENTS

APF is involved in certain legal actions that occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

APF has lease commitments relating to office buildings. The estimated annual operating lease rental payments for the building for the next five years are as follows:

($000)	
2004	773
2005	756
2006	710
2007	706
2008	359

NOTE 18 SUBSEQUENT EVENTS

Underwriting Agreement and prospectus filing

APF and the Underwriters entered into an Underwriting Agreement pursuant to which the Underwriters agreed to offer and the Trust agreed to issue and sell up to 4,765,000 Trust Units at a price of $11.60 per Trust Unit. Closing of the offering and the issue of 4,765,000 Trust Units took place on February 4, 2004. The estimated net proceeds from the offering, after deducting expenses of the issue and after Underwriters' commissions will be in the amount of $52.5 million and will be initially used to repay debt.

Five Year Review (unaudited)

	2003	2002	2001	2000	1999
FINANCIAL ($000 except per unit amounts)					
Revenue before royalties	**165,457**	94,021	69,924	44,974	24,707
Per unit basic	**$5.34**	$4.59	$5.56	$6.53	$4.19
Cash flow (1)	**83,326**	43,788	33,995	23,706	3,334
Per unit basic	**$2.69**	$2.14	$2.70	$3.44	$0.57
Net income (4)	**43,048**	11,365	18,144	14,075	(4,689)
Per unit basic	**$1.32**	$0.55	$1.44	$2.04	$(0.80)
Cash distributions	**68,713**	37,766	37,311	13,899	9,188
Per unit basic	**$2.195**	$1.810	$2.980	$1.995	$1.560
Bank debt	**98,000**	88,000	59,250	25,736	33,171
UNITS OUTSTANDING (000)					
Year-end	**34,074**	22,942	15,584	7,139	5,890
Average	**30,970**	20,470	12,578	6,888	5,890
MARKET					
High	**$12.67**	$11.19	$13.40	$10.40	$9.70
Low	**$9.30**	$9.00	$8.75	$7.00	$7.25
Close	**$12.54**	$9.79	$9.85	$9.75	$8.10
Volume (000)	**41,359**	17,314	11,645	2,520	2,394
Value ($000)	**463,074**	175,935	123,767	21,711	20,196
OPERATIONS					
Production					
Oil (bbl/d)	**6,472**	5,307	3,167	1,152	1,104
Natural gas (mcf/d)	**33,799**	18,488	15,391	13,449	13,656
NGL's (bbls/d)	**358**	144	100	254	274
Total (boe/d)	**12,463**	8,532	5,832	3,648	3,654
Annual (mboe)	**4,549**	3,114	2,129	1,335	1,334
Commodity Sales Prices (net of hedging)					
Oil ($/bbl)	**34.46**	33.66	33.64	41.40	25.00
Natural gas ($/mcf)	**6.32**	3.83	4.94	4.72	2.36
NGL's ($/bbl)	**31.82**	25.15	30.97	35.96	18.19
Average ($/boe)	**35.95**	29.65	31.94	32.98	17.74
Reserves - proved plus probable (2)					
Crude oil & NGL's (mbbl)	**23,789**	20,608	13,545	5,648	6,216
Natural gas (mmcf)	**99,197**	68,290	50,984	46,364	41,366
Total (mboe) (3)	**40,322**	31,989	22,042	13,375	13,110
ECONOMICS ($/boe)					
Average oil & gas sales price (net of hedging)	**35.95**	29.65	31.94	32.98	17.74
Other income	**0.42**	0.54	0.89	0.69	0.77
Net selling price	**36.37**	30.19	32.85	33.68	18.50
Royalties	**7.14**	6.01	6.28	6.39	2.92
Operating costs	**7.12**	6.35	6.15	6.01	5.47
Netbacks	**22.11**	17.83	20.42	21.28	10.11
General & administrative costs	**2.20**	1.49	1.58	1.38	0.85
Management fees	**-**	0.63	0.71	0.74	0.35
Interest	**0.92**	0.91	1.43	1.41	1.47
Taxes	**0.60**	0.61	0.55	0.12	0.07
Site restoration	**0.73**	0.67	0.61	0.68	0.48
Cash flow from operations (1)	**18.32**	14.14	15.97	17.59	7.20

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and accrued interest on convertible debentures.

(2) Reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties for 2002 and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

(3) Boe's may be misleading, particularly if used in isolation. In accordance with NI 51-101, 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.

(4) Net income in the basic per Trust unit calculation has been reduced by interest accrued on the convertible debentures.

Martin Hislop

Chief Executive Officer; Director

Mr. Hislop is a chartered accountant with more than 25 years' experience in all aspects of financing and managing private and public oil and gas corporations, partnerships and trusts. Prior to founding the predecessor of APF Energy in September 1994, Mr. Hislop was the President and CEO of Lakewood Energy Inc., a TSX-listed oil and gas company which was created as a result of the amalgamation of 10 limited partnerships, for whom Mr. Hislop raised in excess of $125 million in equity between 1986 and 1992. During 1984 and 1985, he provided corporate finance consulting services to a Montreal-based investment dealer. Prior to that, Mr. Hislop was Vice-President, Finance for Maxwell Cummings & Sons Holdings Ltd., a private investment company. In that capacity, he participated in the creation and/or financing of several oil and gas companies in which the Cummings group took positions, including Aberford Resources and Marine Oil. Under Mr. Hislop's stewardship, APF Energy Trust has generated an average annual rate of return of 22% since inception, placing the Trust among industry leaders.

Steve Cloutier

President and Chief Operating Officer; Director

Mr. Cloutier has more than 16 years' combined experience in oil and gas, corporate finance, mergers and acquisitions, and law. Since participating in the formation of APF Energy Trust in 1996, Mr. Cloutier has been responsible for the co-ordination of day-to-day operations of the business, and has been directly involved in oil and gas transactions worth more than $400 million. Prior to co-founding APF Energy with Mr. Hislop, Mr. Cloutier practiced law in Toronto with a firm specializing in corporate finance and secured lending. Before that, Mr. Cloutier worked in the investment industry. Mr. Cloutier is a graduate of the University of Victoria (Law) and McGill University (Labour Relations).

Bonnie Nicol

Vice President, Operations

Ms. Nicol is a professional engineer with 19 years' experience in the petroleum industry, and a broad range of expertise in operations, optimization and evaluations. Prior to joining APF in early 1998, Ms. Nicol was responsible for the Provost and Saskatchewan business unit of Northstar Energy Corporation, a senior oil and gas producer. Since graduating from the University of Alberta with a degree in chemical engineering, Ms. Nicol has assumed roles of increasing responsibility at several oil and gas companies. As the leader of the operations team, Ms. Nicol oversees a production base of more than 13,000 boe per day, and a technical staff which operates approximately 90% of its production.

R. Kenneth Pretty

Vice President, Corporate Development and Land

Mr. Pretty is a professional landman with 22 years' experience in the oil and gas industry. After graduating with an economics degree from the University of Calgary, Mr. Pretty joined Norcen Energy's land department, where he was exposed to an extensive range of mandates over a 12-year period. Mr. Pretty joined Amerada Hess in the mid-1990s in a senior land and business development position, and remained with the company following it's acquisition by Petro-Canada. In 1997, Mr. Pretty moved to Newport Petroleums as Vice President, Land, and later became Vice President, Business Development when Newport was acquired by Hunt Oil Company in 2000. He joined APF in mid-2001 and since then has been responsible for the identification, evaluation and execution of all acquisition and divestiture activities, as well as the coordination of the land function.

Alan MacDonald

Vice President, Finance

Mr. MacDonald is a chartered accountant with more than 23 years' experience in public practice and the oil and gas industry. From 1987 to 1999, Mr. MacDonald was Vice President, Finance of Starvest Capital Inc. which, among its other mandates, managed Starcor Energy Royalty Fund and Orion Energy Trust, two publicly-traded oil and gas royalty trusts. Most recently, he was Vice President, Finance of Due West Resources Inc., a private oil and gas company. In his position, Mr. MacDonald leads the team that is responsible for all financial, treasury and administrative functions for APF Energy Trust.

John Ewing

Vice President, GeoScience

Mr. Ewing is a professional geologist with more than 26 years of experience in the oil and gas industry. Following graduation with an honours degree in earth sciences from the University of Waterloo in 1978, Mr. Ewing began his career with Husky Oil. After working in both technical and managerial positions at several oil and gas companies, Mr. Ewing joined Tethys Energy Inc. in 1996, as Vice President, Exploration, where he oversaw an exploration program that contributed to the growth of the company from 650 boe/d in late 1996 to 3,400 boe/d by early 2000. Prior to joining APF, Mr. Ewing was President of a private resources and consulting firm. In his position, Mr. Ewing is responsible for overseeing the geological and geophysical aspects of APF Energy Trust.

Dan Allan

Vice President, Coalbed Methane

Mr. Allan is a professional geologist registered in both Alberta and the state of Wyoming, with more than 28 years of experience in the oil and gas industry. Following graduation with an honours degree in geology from McGill University in 1975, Mr. Allan began his career with Texaco Exploration, where he spent six years in Western Canada. In 1981 he moved to Dome Petroleum in Denver, Colorado and spent the next 14 years in the U.S. In 1994 he commenced employment with MAXX Petroleum as Exploration Manager and subsequently founded CanScot Resources Ltd. in 1997 as President and CEO. CanScot was acquired by APF in September of 2003. In recent years, Mr. Allan has become involved in coalbed methane ("CBM") exploration and development in both Canada and the U.S. In his position, Mr. Allan is responsible for overseeing the CBM division at APF Energy Trust.

Directors

Don Engle

Independent Director and Chairman of the Board

Board Committees: Audit, Reserves, Compensation

Mr. Engle has been President of Sapphire Resources Ltd., a private oil and gas consulting company since 1985. Since September, 2003 Mr. Engle has been Director and Chief Operating Officer of Welton Energy Corporation, a junior oil and gas company. From 1996 – 2000, Mr. Engle was President of Grey Wolf Exploration Inc., a publicly traded oil and gas company listed on the Toronto Stock Exchange. Mr. Engle is a professional landman, with more than 34 years of experience in the petroleum industry.

William Dickson

Independent Director

Board Committees: Audit, Reserves

Mr. Dickson brings to APF Energy Trust more than 45 years' of technical, management and public company experience in the oil and gas industry. He is active as principal of Arlyn Enterprises Ltd., a private lubricants company and serves on the Board of IMS Petroleum Ltd. Previously, he has held senior executive and/or Board positions with Stampeder Exploration Ltd., Ultramar Oil and Gas Canada Ltd., and numerous non-profit societies.

Daniel Mercier

Independent Director

Board Committees: Audit, Reserves, Compensation

Mr. Mercier is a professional engineer with extensive experience in the operation, management and capitalization of oil and gas companies. Throughout the past nine years he has been President of Asia Energy Ltd., a private Alberta corporation which he initiated in 1995 that holds interests in Russia. Since September, 1998, Mr. Mercier has been Vice President, Operations for SOCO International plc, a publicly traded United Kingdom corporation engaged in international oil and natural gas exploration and production. Prior to that, he was Chairman, Chief Executive Officer and a Director of Territorial Resources Inc., a publicly traded U.S. oil and gas exploration company which merged with SOCO. From January of 1996 to March of 1996, Mr. Mercier was employed by Chancellor Energy Resources Inc. as Chief Operating Officer to assist with the sale of the company to HCO Energy Ltd. Prior to January of 1996, he was President and Chief Executive Officer of Canadian Conquest Explorations Inc. Each of Chancellor, HCO and Canadian Conquest were publicly listed Alberta corporations.

Robert MacDonald

Independent Director

Board Committees: Audit, Reserves

Mr. MacDonald was a Director, Commercial Banking, CIBC World Markets, a subsidiary of a Canadian Chartered Bank from October 1998 to May 2003. From March 1998 to October 1998 he was Managing Director, Koch Capital, the merchant banking arm of a private U.S. based energy company. From 1993 to March 1998, Mr. MacDonald was Vice President, Oil & Gas Group, Canadian Imperial Bank of Commerce. Prior to that, he spent 17 years in other positions within the financial services industry.

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STOCK EXCHANGE LISTING
Toronto Stock Exchange
Symbols: AY.UN and AY.DB

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbl	barrel
bcf	billion cubic feet
boe	barrels of oil equivalent*
boe/d	barrels of oil equivalent per day*
CBM	coalbed methane
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent*
mmboe	million barrels of oil equivalent*
mmbtu	million British thermal units
mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
NGL	natural gas liquid
NPV	net present value
P+P	proved plus probable
tcf	trillion cubic feet
WTI	West Texas Intermediate

*6 mcf of gas = 1 barrel of oil

DIRECTORS AND OFFICERS

Don Engle
Independent Director and
Chairman of the Board (1) (2) (3)

William Dickson
Independent Director (1) (3)

Daniel Mercier
Independent Director (1) (2) (3)

Robert MacDonald
Independent Director (1) (3)

Martin Hislop
Director
Chief Executive Officer

Steven Cloutier (2)
Director
President & Chief Operating Officer

Bonnie Nicol
Vice President, Operations

Ken Pretty
Vice President, Corporate Development and Land

Alan MacDonald
Vice President, Finance

John Ewing
Vice President, GeoScience

Dan Allan
Vice President, Coalbed Methane

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Reserves Committee

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No marmots were harmed in the making of this annual report.

Printed in Canada

APF ENERGY TRUST

Information Circular - Proxy Statement

for the Annual General and Special Meeting of Unitholders
to be held on Tuesday, May 18, 2004

SOLICITATION OF PROXIES

This Information Circular - Proxy Statement is furnished in connection with the solicitation of proxies by management of APF Energy Inc. ("APF"), on behalf of APF Energy Trust (the "Trust") for use at the Annual General and Special Meeting (the "Meeting") of the holders (the "Unitholders") of trust units ("Trust Units") of the Trust to be held on the 18th day of May, 2004, at 3:00 p.m. (Calgary time) at the Sun Life Plaza Conference Centre, Mezzanine Level, 140 – 4th Avenue SW, Calgary, Alberta, and at any adjournment thereof, for the purposes set forth in the Notice of Annual General and Special Meeting. Instruments of Proxy must be received by Computershare Trust Company of Canada (the "Trustee") Attention: Proxy Department, at 9th Floor, 100 University Avenue, Toronto, Ontario, M5J 2Y2, not less than 24 hours before the time for the holding of the Meeting or any adjournment thereof. The Trustee has fixed the record date for the Meeting at the close of business on April 16, 2004 (the "Record Date"). Only Unitholders of record at the Record Date are entitled to receive notice of the Meeting. Unitholders of record will be entitled to vote those Trust Units owned by them and included in the list of Unitholders entitled to vote at the Meeting prepared as of the Record Date even though the Unitholder has since disposed of his or her Trust Units. No Unitholder who became a Unitholder after the Record Date shall be entitled to vote at the Meeting.

The instrument appointing a proxy shall be in writing and shall be executed by the Unitholder or his attorney authorized in writing or, if the Unitholder is a corporation, under its corporate seal or by an officer or attorney thereof duly authorized.

The persons named in the enclosed form of proxy are Directors of APF. Each Unitholder has the right to appoint a proxyholder other than the persons designated in the form of proxy, who need not be a Unitholder, to attend and to act for him and on his behalf at the Meeting. To exercise such right, the names of the nominees of management should be crossed out and the name of the Unitholder's appointee should be legibly printed in the blank space provided.

REVOCABILITY OF PROXY

A Unitholder who has submitted a proxy may revoke it at any time prior to the exercise thereof. If a person who has given a proxy attends personally at the Meeting at which such proxy is to be voted, such person may revoke the proxy and vote in person. In addition to revocation in any other manner permitted by law, a proxy may be revoked by instrument in writing executed by the Unitholder or his attorney authorized in writing or, if the Unitholder is a corporation, under its corporate seal or by an officer or attorney thereof duly authorized and deposited either at the office of the Trustee at the address set out above or at the head office of APF at any time up to and including the last business day preceding the day of the Meeting, or any adjournment thereof, at which the proxy is to be used, or with the Chairman of the Meeting on the day of the Meeting, or any adjournment thereof, and upon either of such deposits, the proxy is revoked.

PERSONS MAKING THE SOLICITATION

The solicitation is made on behalf of the Trust. The costs incurred in the preparation and mailing of the Instrument of Proxy, Notice of Annual General and Special Meeting and this Information Circular - Proxy Statement will be borne by the Trust. In addition to solicitation by mail, proxies may be solicited by personal interviews, telephone or other means of communication and by Directors, Officers and employees of APF, who will not be specifically remunerated therefor.

EXERCISE OF DISCRETION BY PROXY

The Trust Units represented by proxy in favour of management nominees shall be voted on any ballot at the Meeting and, where the Unitholder specifies a choice with respect to any matter to be acted upon, the Trust Units shall be voted on any ballot in accordance with the specification so made.

In the absence of such specification, the Trust Units will be voted in favour of the matters to be acted upon. The persons appointed under the Instrument of Proxy furnished by the Trust are conferred with discretionary authority with respect to amendments or variations of those matters specified in the Instrument of Proxy and Notice of Annual General and Special Meeting. At the time of printing this Information Circular - Proxy Statement, neither APF nor the Trustee knows of any such amendment, variation or other matter.

VOTING TRUST UNITS AND PRINCIPAL HOLDERS THEREOF

The Trust is authorized to issue 500,000,000 Trust Units and Special Voting Units. As of the date hereof, 39,670,014 Trust Units and no Special Voting Units are issued and outstanding. At the Meeting, upon a show of hands, every Unitholder present in person or represented by proxy and entitled to vote shall have one vote. On a poll or ballot, every Unitholder present in person or by proxy has one vote for each Trust Unit, in respect of which he is the registered holder. All votes on special resolutions shall be by a poll and no demand for a poll shall be necessary.

When any Trust Unit is held jointly by several persons, any one of them may vote at the Meeting in person or by proxy in respect of the Trust Unit, but if more than one of them shall be present at such meeting in person or by proxy, and such joint owners of the proxy so present disagree as to any vote to be cast, the joint owner present or represented whose name appears first in the register of Unitholders maintained by the Trustee shall be entitled to cast such vote.

To the best of the knowledge of the Trustee and the Directors and senior Officers of APF, there is no person or corporation which beneficially owns, directly or indirectly, or exercises control or direction over Trust Units carrying more than 10% of the voting rights attached to the issued and outstanding Trust Units of the Trust which may be voted at the Meeting.

The number of Trust Units of the Trust that are owned, directly or indirectly, by all Directors and Officers of APF and their associates as group is 677,478 (1.71% of the outstanding Trust Units). In addition, the Directors, Officers and employees of APF hold options and rights entitling them as a group to acquire an additional 2,293,538 Trust Units of the Trust.

VOTING OF TRUST UNITS - ADVICE TO BENEFICIAL HOLDERS

The information set forth in this section is of significant importance to many Unitholders of the Trust, as a substantial number of the Unitholders do not hold Trust Units in their own name. Unitholders who do not hold their Trust Units in their own name (referred to in this Information Circular as "Beneficial Holders") should note that only proxies deposited by Unitholders whose names appear on the records of the Trust as the registered holders of Trust Units can be recognized and acted upon at the Meeting. If Trust Units are listed in an account statement provided to a Unitholder by a broker, then in almost all cases those Trust Units will more likely be registered under the name of the broker or an agent of a broker. In Canada, the vast majority of such Trust Units are registered under the name of CDS & Co., (the registration name for The Canadian Depositary for Securities, which acts as nominee for many Canadian brokerage firms). Trust Units held by brokers or their nominees can only be voted (for or against resolutions) upon the instructions of the Beneficial Holder. Without specific instructions, brokers/nominees are prohibited from voting Trust Units for their clients. The Trustee of the Trust does not know for whose benefit the Trust Units registered in the name of CDS & Co. are held. Therefore, Beneficial Holders cannot be recognized at the Meeting for purposes of voting the Trust Units in person or by way of proxy, except as set out below.

Applicable regulatory policy requires intermediaries/brokers to seek voting instructions from Beneficial Holders in advance of meetings. Every intermediary/broker has its own mailing procedures and provides its own return instructions, which should be carefully followed by Beneficial Holders in order to ensure that the Trust Units are voted at the Meeting. Often, the form of proxy supplied to a Beneficial Holder by its broker is identical to that provided to registered Unitholders. However, its purpose is limited to instructing the registered Unitholder how to vote on behalf of the Beneficial Holder. The majority of brokers now delegate responsibility for obtaining instructions from clients to ADP Investor Communications ("ADP"). ADP typically mails a scannable Voting Instruction Form in lieu of the form of proxy. The Beneficial Holder is requested to complete and return the Voting Instruction Form to them by mail or facsimile. Alternatively, the Beneficial Holder can call a toll-free number to vote the Trust Units held by the Beneficial Holder. ADP then tabulates the results of all instructions received and provides appropriate instructions respecting the voting of Trust Units to be represented at the Meeting. A Beneficial Holder receiving a Voting Instruction Form cannot use that Voting Instruction Form to vote Trust Units directly at the Meeting as the Voting Instruction Form must be returned as directed by ADP well in advance of the Meeting in order to have the Trust Units voted.

IF YOU ARE A BENEFICIAL UNITHOLDER AND WISH TO VOTE IN PERSON AT THE MEETING, PLEASE CONTACT YOUR BROKER OR AGENT WELL IN ADVANCE OF THE MEETING TO DETERMINE HOW YOU CAN DO SO.

QUORUM FOR MEETING

At the Meeting, a quorum shall consist of two or more persons either present in person or represented by proxy and representing in the aggregate not less than 10% of the outstanding Trust Units. Generally, if a quorum is not present at a meeting within one half an hour after the time fixed for the holding of the meeting, it shall stand adjourned to such day being not less than fourteen (14) days later and to such place and time as may be determined by the Chairman of the meeting. At such meeting, the Unitholders present either personally or by proxy shall form a quorum. In the case of the Meeting, at which a special resolution is under consideration, such adjournments are required to be for not less than 21 days nor more than 60 days and notice is to be given at least 10 days prior to the date of the adjourned meeting.

MATTERS TO BE ACTED UPON AT MEETING

1. Re-Appointment of Trustee

The Trust Indenture by which the Trust was formed provides that the Unitholders shall, at each annual meeting, re-appoint or appoint a successor to the Trustee. Accordingly, Unitholders will consider an ordinary resolution to appoint Computershare Trust Company of Canada ("Computershare") as trustee of the Trust. Computershare, or its predecessor, The Trust Company of Bank of Montreal, has been trustee of the Trust since formation on October 10, 1996.

The Board of Directors recommends that Unitholders approve the Trustee Re-Appointment Resolution.

The form of Trustee Re-Appointment Resolution is set forth in Schedule "A".

2. The Trust Unit Incentive Rights Plan Amendment

The Trust has established an option plan (the "Original Plan") and an incentive rights plan (the "Incentive Rights Plan"), together the "Plans" (as defined and described below under "Trust Unit Incentive Plan and Trust Unit Incentive Rights Plan").

Since the formation of the Original Plan, options to acquire 546,723 Trust Units have been granted under the Original Plan. Of these, 317,578 options have been exercised and 115,609 have been cancelled or expired, leaving 113,536 that have not been exercised and are outstanding. No new grants will be made under the Original Plan.

The Incentive Rights Plan currently provides that the maximum number of Trust Units issuable thereunder is 2,600,000. There has been a total of 2,499,622 rights granted under the Incentive Rights Plan. Of these, 141,371 have been exercised and 178,249 have been cancelled or expired, leaving 2,180,002 outstanding. Those which have been cancelled or expired are added back into the reserve. As a result, the current reserve is 278,627, calculated as follows: ((2,600,000 – 2,499,622) + 178,249)=278,627.

Since the number of outstanding Trust Units has increased from 3,500,000 to 39,670,014 since the Original Plan was implemented, as a result of the expansion of the business of APF and the Trust, the Board of Directors considers that it is desirable to increase the maximum number of Trust Units issuable under the Incentive Rights Plan. In addition, the Board of Directors wishes to have sufficient Trust Units issuable pursuant to the Incentive Rights Plan to enable APF to attract and retain people of experience and ability, for the benefit of the Trust.

The Toronto Stock Exchange ("TSX") requires that a listed company specify the maximum number of securities that are issuable pursuant to its incentive plans. The TSX requires that a listed company seek securityholder approval to increase this maximum number.

The Unitholders will be asked to consider and, if deemed advisable, to approve, by a majority of votes cast at the Meeting, (excluding votes attached to securities beneficially owned by insiders to whom Trust Units may be issued pursuant to the Plans and their associates) a resolution (the "Trust Unit Incentive Rights Plan Amendment Resolution") to increase the maximum number of Trust Units issuable under the Incentive Rights Plan, from 2,600,000 to 3,200,000 (an increase of 600,000). The maximum of 3,200,000 under the Incentive Rights Plan is 8.1% of the outstanding Trust Units (and together with the options outstanding under the Original Plan is 8.4%). This will increase the reserve under the Incentive Rights Plan from 278,627, to 878,627. As a result, APF will have room to grant an additional 878,627 rights.

APF has demonstrated a strong track record of reserve and production replacement through development and optimization technologies. Going forward, the APF Business Plan is predicated on an even more active capital expenditure program, which will require the retention and hiring of technical and support staff. It is essential that APF have room under the Plans to ensure that total compensation is competitive with the industry.

As at the date hereof, to the knowledge of APF Energy, 677,478 Trust Units held by insiders or their associates will be excluded from the vote on this resolution, representing approximately 1.71% of the issued and outstanding Trust Units of the Trust.

The Board of Directors recommends that Unitholders approve the Trust Unit Incentive Rights Plan Amendment Resolution.

The form of Trust Unit Incentive Rights Plan Amendment Resolution is set forth in Schedule "A".

3. Amendment of Trust Indenture

APF and the Trustee are parties to a trust indenture ("Trust Indenture") originally made October 10, 1996, as amended and restated, by which the Trust was formed and is governed.

At the time of the formation of the Trust, it was proposed that the Trust provide continuous disclosure material to Unitholders substantially similar to that which would be required to be delivered to shareholders of corporations under corporate and securities laws. In particular, Section 16.3 of the Trust Indenture provides that "The Trustee will mail: (a) to each Unitholder, within 140 days after the end of each Year, the audited consolidated financial statements of the Trust for the most recently completed Year together with the report of the Auditors thereon; and ..." and the first sentence of Section 16.2 provides that "The Trustee will mail to each Unitholder, within 60 days after the end of each Quarter, unaudited financial statements of the Trust for the most recent Quarter".

A recent initiative of the Canadian securities regulators, National Instrument 51-102 *Continuous Disclosure Obligations*, has implemented changes with respect to the requirement for reporting issuers such as the Trust to deliver annual financial statements and management's discussion & analysis ("MD&A") and interim financial statements and MD&A to securityholders. It provides that a reporting issuer must send annually a request form to the registered holders and beneficial owners of its securities, that the registered holders and beneficial owners may use to request a copy of the reporting issuer's annual financial statements and MD&A for the annual financial statements, the interim financial statements and MD&A for the interim financial statements, or both. If a registered holder or a beneficial owner requests the reporting issuer's annual or interim financial statements, the reporting issuer must send a copy of the requested financial statements to the person or company that made the request, without charge, by the later of (a) the filing deadline for the financial statements requested; and (b) 10 calendar days after the issuer receives the request. Otherwise, there is no obligation to send such material.

The Trust supports this change in disclosure requirements, as annual financial statements and MD&A and interim financial statements and MD&A are filed on www.sedar.com and are generally available for review by anyone who wants to see them. In addition, the Trust supports the reduction of wasteful use of paper and this includes the delivery of voluminous paper copies of public disclosure materials that Unitholders may not wish to receive in paper form. As a result, the Board of Directors of APF has determined it is appropriate and in the best interest of Unitholders that Section 16.3(a) and that portion of Section 16.2 of the Trust Indenture, which mandates the delivery of interim financial statements to all Unitholders on a quarterly basis, be deleted. The result of this will be that the Trust will deliver only to those Unitholders who request them annual financial statements and MD&A and interim financial statements and MD&A.

Accordingly, Unitholders will be asked at the Meeting to consider and, if thought appropriate, to pass a Special Resolution to amend the Trust Indenture to delete Section 16.3(a) and the first sentence of Section 16.2 (the "Trust Indenture Amendment Resolution").

The Board of Directors recommends that Unitholders approve the Trust Indenture Amendment Resolution.

The form of Trust Indenture Amendment Resolution is set forth in Schedule "A".

4. **Amendment of Royalty Agreements**

APF and the Trustee are parties to a royalty agreement originally made December 17, 1996, as amended and restated, and 990009 Alberta Inc., as general partner of APF Energy Limited Partnership, and the Trustee are parties to a royalty agreement originally made May 30, 2002, as amended and restated (collectively, the "Royalty Agreements").

The Royalty Agreements currently define "Proved Reserves" and "Probable Reserves" as these terms were defined under National Policy 2-B. A recent initiative of the Canadian securities regulators, National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), has imposed new definitions of proved reserves and probable reserves on the industry as a whole. In particular, the new definitions of proved reserves and probable reserves contain specific quantifications of levels of certainty of 90% for proved reserves and of 50% for proved plus probable reserves.

As a result, the Royalty Agreements contain definitions of proved reserves and probable reserves that do not comply with the new reserve definitions under NI 51-101. This impacts on the calculation of "Asset Value" for the purposes of determining when Board of Directors' or Unitholders' approval is required on a sale of properties under Section 9.2 of the Royalty Agreements, and for the purposes of determining the threshold amounts that may be borrowed to acquire properties, such borrowings to be secured by a charge on such properties in priority to the royalty payable to the Trust under Section 10.3(b) of the Royalty Agreements, in that the definition of "Asset Value" in the Royalty Agreements is based on the National Policy 2-B definitions of proved reserves and probable reserves.

The Board of Directors of APF has therefore determined it would be prudent and expeditious to amend the definitions of "Asset Value", "Proved Reserves" and "Probable Reserves" in the Royalty Agreements to reflect the prescribed definitions in NI 51-101. The proposed definition of "Asset Value" is as follows: "Asset Value" means, in respect of a Property, the present worth of all of the estimated pre-tax net revenue from the proved reserves and the probable reserves shown in the most recent engineering report relating to such Property, discounted at 15% per annum and based on escalated pricing and cost assumptions;" and "proved reserves" and "probable reserves" shall have the meaning ascribed to them in National Instrument 51-101.

Accordingly, Unitholders will be asked at the Meeting to consider and, if thought appropriate, to pass a Special Resolution (the "Royalty Agreements Amendment Resolution") authorizing the Board of Directors to amend the definitions of "Proved Reserves" and "Probable Reserves" in the Royalty Agreements.

The Board of Directors recommends that Unitholders approve the Royalty Agreements Amendment Resolution.

The form of Royalty Agreements Amendment Resolution is set forth in Schedule "A".

5. **Election of Directors of APF**

The Trust Indenture provides that the members of the Board of Directors of APF are to be selected by a vote of Unitholders at a meeting of Unitholders held in accordance with the Trust Indenture and that following such meeting the Trustee shall elect the individuals so selected by the Unitholders to the Board of Directors of APF.

Six (6) nominees have been nominated as Directors of APF to hold office until the next annual general meeting, or until their successors are duly elected or appointed or until a Director vacates his office.

The names and municipalities of residence of the six persons nominated for selection as Directors of APF by Unitholders, the number of Trust Units of the Trust beneficially owned, directly or indirectly, or over which each exercises control or direction, the offices held by each in APF, the period served as Director and the principal occupation of each are as follows:

Name and Municipality of Residence	Number of Trust Units Beneficially Owned or Controlled	Offices Held and Time as Director	Principal Occupation
Martin Hislop Calgary, Alberta	254,421(4)(6)	Chief Executive Officer and formerly President; Director since December 8, 1995	Chief Executive Officer of APF
Steven Cloutier(2) Calgary, Alberta	266,372(4)(6)	President, Chief Operating Officer, Corporate Secretary and Treasurer; Director since December 8, 1995	President and Chief Operating Officer of APF

Name and Municipality of Residence	Number of Trust Units Beneficially Owned or Controlled	Offices Held and Time as Director	Principal Occupation
Donald Engle(1)(2) Calgary, Alberta	23,008(5)	Director since December 1, 2000 and Chairman of the Board since March 19, 2002	President of Sapphire Resources Ltd., a private oil and gas consulting company and Director and Chief Operating Officer of Welton Energy Corporation, a junior oil and gas company
Daniel Mercier(1)(2) Okotoks, Alberta	6,661(5)	Director since October 1, 1996	Operations Advisor, SOCO International plc, an international oil and gas exploration company and President of Asia Energy Ltd., a private oil and gas company
William Dickson(1) Calgary, Alberta	15,830(5)	Director since November 1, 1996	Director of Dickson Resources Inc., an oil and gas company and a Director of IMS Petroleum Ltd.
Robert MacDonald(1) Calgary, Alberta	Nil(5)	Director since June 11, 2003	Retired businessman. Director, Commercial Banking, CIBC World Markets from October, 1998 to May 2003; prior thereto, Managing Director of Koch Capital, the merchant banking arm of a private U.S. based energy company from March 1998 to October 1998

Notes:

(1) Member of the Audit and Reserves Committee.
(2) Member of the Compensation Committee.
(3) The Trust does not have an executive committee of its Board of Directors.
(4) Mr. Hislop holds options and rights to acquire 186,344 Trust Units at exercise prices between $9.67 and $12.17 and Steven Cloutier holds options and rights to acquire 171,844 Trust Units at exercise prices between $8.00 and $12.17.
(5) Messrs. Mercier, Dickson, Engle and MacDonald hold 19,358, 19,913, 21,179 and 14,358 options and rights, respectively, to acquire Trust Units.
(6) Of the Trust Units held by Messrs. Hislop (directly and indirectly) and Cloutier, 81,396 and 96,678 Trust Units respectively are subject to escrow agreements entered into as a result of the internalization of management of the Trust in January, 2003. These Trust Units are releasable from escrow, in the case of Mr. Hislop, as to one-half on each of January 3, 2005 and 2006 and in the case of Mr. Cloutier, as to one-third on each of January 3, 2005, 2006 and 2007.

Martin Hislop was an officer of APF Energy Management Inc. (the "Manager") since September of 1994 and became an Officer of APF in December, 1995. From 1986 to July of 1994, Mr. Hislop was President and Chief Executive Officer of Lakewood Energy Inc. and its predecessor, Lakewood Capital Group Inc.

Steven Cloutier was an officer of the Manager since September of 1994 and became an officer of APF in December, 1995. Prior to 1994, Mr. Cloutier was in private law practice.

Mr. Engle is a professional Landman and has been President of Sapphire Resources Ltd., a private oil and gas consulting company, since 1975. He has also been a Director and Chief Operating Officer of Welton Energy Corporation, a junior oil and gas company since August, 2003. From 1996 to May, 2000, Mr. Engle was also President of Grey Wolf Exploration Inc., a publicly traded oil and gas company listed on the TSX. He was also a Director of CanScot Resources Ltd. until its acquisition by APF in September, 2003.

Mr. Mercier is an Operations Advisor for SOCO International plc ("SOCO"). From September, 1998 until February, 2004 he was Vice-President, Operations for SOCO. He has also been the President of Asia Energy Ltd., a private oil and gas company since its inception in 1995. Prior thereto he was Chairman, Chief Executive Officer and a Director of Territorial Resources, Inc., a Colorado company engaged in international oil and natural gas exploration, which merged with SOCO on September 8, 1998. SOCO is a publicly traded United Kingdom corporation engaged in international oil and natural gas exploration and production.

Mr. Dickson is a consultant, and has provided oilfield operations advice to oil and gas and service companies since 1989, upon retirement as Vice President, Production of Ultramar Oil and Gas Canada Ltd. During that time, he has also been a Director of Dickson Resources Inc., an oil and natural gas company and Arlyn Enterprises Ltd., a vendor of commercial and consumer lubrication oils. From November, 1995 to January, 1997, he was Vice-President of 3-D Reclamation Inc., a company carrying on the business of abandoning and related reclamation of oil and gas wells.

Mr. MacDonald is a retired businessman. He was Director, Commercial Banking, CIBC World Markets, a subsidiary of a Canadian Chartered Bank, from October, 1998 to May, 2003. From March, 1998 to October, 1998 he was Managing Director, Koch Capital, the merchant banking arm of a private, U.S. based energy company. From 1993 to March, 1998, Mr. MacDonald was Vice President, Oil & Gas Group, Canadian Imperial Bank of Commerce. Prior to that, he spent 17 years in other positions within the financial services industry.

The information as to securities beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to the Trust by the respective persons whose names appear above.

6. **Appointment of Auditors of the Trust**

The Trust Indenture provides that the auditors of the Trust will be selected at each annual meeting of Unitholders. Accordingly, Unitholders will consider an ordinary resolution to appoint the firm of PricewaterhouseCoopers LLP, Chartered Accountants, Calgary, Alberta, to serve as auditors of the Trust until the next annual meeting of the Unitholders and to authorize the Directors of APF to fix the remuneration of the auditors. PricewaterhouseCoopers LLP have been the auditors of the Trust since its formation on October 10, 1996.

EXECUTIVE COMPENSATION

On December 18, 2002, Unitholders approved the internalization of management of the Trust and, in connection with the acquisition of the Manager on January 3, 2003 by the Trust, the external management contract structure of the Trust and all related fees were eliminated.

The Board of Directors of APF has appointed a compensation committee that is comprised of Donald Engle and Daniel Mercier, two unrelated Directors and Steven Cloutier, a management Director.

Report Of The Compensation Committee

Executive Compensation

APF is a wholly-owned subsidiary of the Trust, and currently has a majority of unrelated Directors who are elected by the Unitholders. Because 2003 represented the first year of operations with internalized management, the Board of Directors of APF as a whole resolved to review the issue of employee compensation, rather than delegating the responsibility to the Compensation Committee. Going forward, the Compensation Committee will have primary responsibility for this function and make recommendations to the board.

The unrelated members of the APF Board of Directors determined that one of the objectives of the internalization should be a go-forward compensation structure that placed APF employees at median industry levels, based on the oil and gas industry as a whole, for base salary, with the opportunity for top-quartile total compensation through a short-term incentive plan ("STIP"). As the Trust has been one of the industry's best performers since inception, the unrelated members of the APF Board wanted to ensure total employee compensation provided an incentive to continue to generate strong returns.

In order to have access to additional resources, the Board of Directors of APF retained an independent consulting firm in late 2002 to provide advice in helping to determine a range of compensation levels. In particular, the mandate of the consultants was to review executive compensation, relative to other oil and gas companies and trusts of comparable size.

After considering the objectives of the internalization, relevant data from the independent consulting firm and other sources of compensation information, the independent members of the APF Board approved 2003 compensation and implemented a new STIP, the first payment under which was made in early 2004.

Base Salary

All APF employees receive base salaries commensurate with industry standards. APF had six named Executive Officers throughout 2003, as that term is defined by the *Securities Act*, Ontario. In the case of the Chief Executive Officer and President, each earned a base 2003 salary of $248,000. In the case of the four Vice Presidents, each earned a base 2003 salary of $168,000. The unrelated members of the Board of APF were responsible for fixing the salaries of the officers, while the salaries of the staff were fixed by management.

STIP

The APF Short Term Incentive Plan ("STIP") is intended to provide employees of APF with an opportunity to earn additional income as a result of superior corporate and individual performance. Together with base salary, the Trust Unit Incentive Plan and the Trust Unit Incentive Rights Plan, the STIP comprises an important component of employee compensation, one that is designed to encourage employees to contribute to the success of APF and the Trust.

In order to attract and retain qualified employees, the STIP has been structured to provide high payments in years where corporate performance is outstanding and the Unitholders have been rewarded with top-level returns.

The STIP comprises two components: the Group Bonus, linked to the financial performance of the Trust; and the Performance Bonus, measured in relation to an employee's individual performance.

1. The Group Bonus

The first component of the STIP is the creation of the bonus pool, from which the Group Bonus will be paid. The significant elements of the Group Bonus are as follows:

- It will be shared by all APF employees, regardless of position within the organization.
- The aggregate amount to be paid into the pool will be calculated in accordance with a formula based on the Trust's total return per unit and the Trust's cash flow, as described below.
- Payment to individual employees will be made pro rata to their base salaries as a percentage of total corporate payroll.

Total Return

Total return is calculated as the sum of the appreciation (or depreciation) in the price of the Trust Units and the annual distribution, divided by the Trust Unit price at the beginning of the year.

- Example using 2003 actual figures

Trust Unit price, beginning of the year	$ 9.79
Trust Unit price, end of the year	$12.48*
Price appreciation	$ 2.69
Distributions during the year	$ 2.19
Total return	$ 4.88
Total return, as a percent	49.85%

* In order to limit volatility, the "year-end unit price" is calculated as the volume-weighted average price during the 10 trading days immediately prior to January 1, and the 10 trading days immediately following January 1.

By taking into consideration total return per unit, employee STIP compensation is in alignment with the interests of Unitholders. **In order for any payment to be made into the Bonus Pool, a minimum total return of 10% must be achieved.**

Cash Flow

The second component of the Group Bonus is related to the Trust's cash flow, on a gross basis. Cash flow is calculated as all revenues less operating costs, royalties and other expenses of running the Trust, before taking into account the expenses related to the STIP. By taking into consideration cash flow, employee STIP compensation is related to the growth of the business, but only if a minimum total return is achieved.

Calculation of the Bonus Pool and Payment of the Group Bonus

The quantum to be paid into the Bonus Pool is calculated in accordance with the formula set out in Table 1. As both total return and net operating income increase, the amount of the Bonus Pool will increase.

Table 1

Total Return	Bonus Rate
<10%	0.00%
10-15%	1.08%
15-20%	1.30%
20-25%	1.56%
25-30%	1.87%
30-35%	2.24%
35-40%	2.69%
40-45%	3.22%
45-50%	3.87%
50-55%	4.64%
55-60%	5.57%
60-65%	6.69%
65-70%	8.02%
70-75%	9.63%
75-80%	11.56%
80-85%	13.87%
85%+	16.64%

Once the Bonus Pool is calculated, individual amounts paid as part of the Group Bonus are calculated based on an individual employee's Base Salary for the recently completed year as a percentage of total company payroll.

2. The Performance Bonus

In order to recognize individual achievement that has helped to contribute to the success of the Trust, the Board of Directors of APF has considered that a portion of the STIP should be derived from a variety of individual performance measures.

Eligibility to receive a Performance Bonus is dependent on an employee's seniority within the organization. The Compensation Committee of the Board of Directors of APF is authorized to determine all Performance Bonuses, which ultimately are approved in the discretion of the APF Board of Directors.

Group RRSP/Savings Plan

APF has a group RRSP whereby officers and employees are eligible to receive up to 5% of base salary by way of a matching contribution to a group RRSP, subject to certain limits. The plan also has a savings component, for those employees who do not wish to contribute to an RRSP.

Option/Rights Plan ("Incentive Plan")

APF has an Incentive Plan that is a combination of two plans: one originally created when the Trust was formed in 1996; and another in 2001, in response to the evolution of the oil and gas royalty trust industry.

The first plan (the "Original Plan") is a conventional option plan, whereby options to acquire Trust Units were issued at the then current market price. The options vested in one-third increments on the first, second and third anniversaries of their grant.

In 2001, APF ceased granting options under the Original Plan, after Unitholders approved a Trust Unit rights incentive plan (the "Incentive Rights Plan"). Unlike many public issuers, APF did not re-price and merge the two plans; rather, the Original Plan was frozen. The Incentive Rights Plan was similar to the Original Plan, except that the strike price of the right may be reduced, at the election of the holder, in accordance with a formula linked to Unitholder distributions and book value of assets. Otherwise, there is the same one-third vesting rule.

Employment Agreements

All of the officers have entered into employment agreements with APF. Among the principal terms contained therein are provisions which call for a severance payment if the officer's employment is terminated without cause. The provisions also apply if there is a change in control of the Trust. In the case of the Chief Executive Officer and the President, each is entitled to receive a payment equal to the aggregate of two times the preceding year's base salary, STIP payment and benefits. In the case of the Vice Presidents, each is entitled to receive a payment equal to the aggregate of one times the preceding year's base salary, STIP payment and benefits.

Compensation of the President and the Chief Executive Officer ("CEO")

The factors considered by the Compensation Committee in determining total compensation for the President and the CEO, as well as the manner in which these factors are reviewed, are similar to those used in determining total compensation for the other executives of APF. However, in the case of the President and the CEO, more weight is given to the overall performance of the Trust as well as the President and CEO's performance in such areas as leadership, execution and strategic planning.

This report is furnished by the Compensation Committee.

Donald Engle
Daniel Mercier
Steven Cloutier

Performance Chart

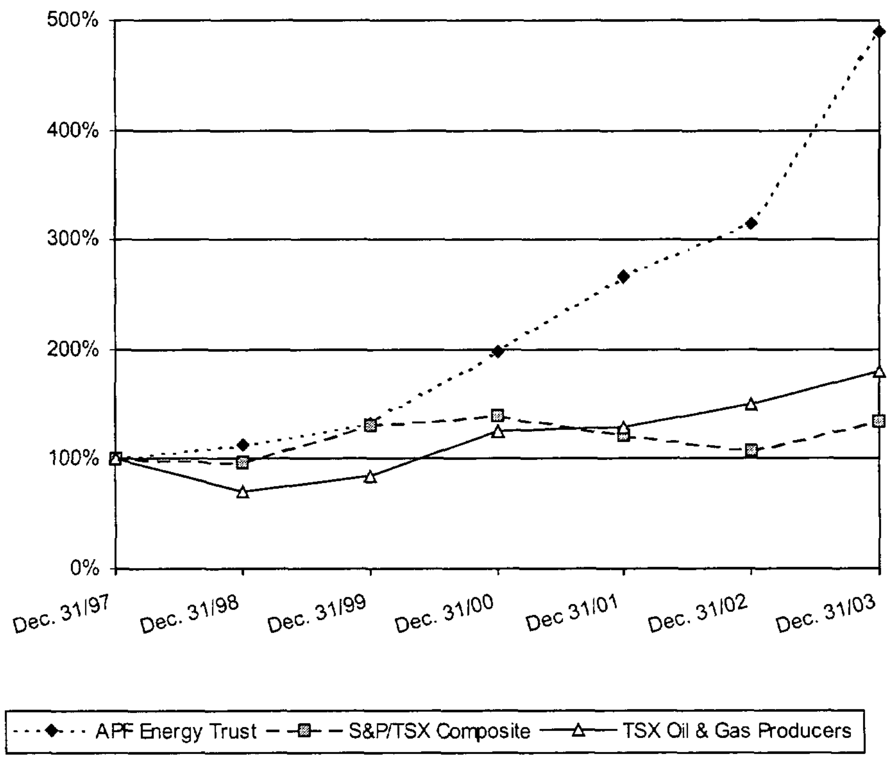
The following graph and table compare the change in the cumulative Unitholder return from December 31, 1997 until December 31, 2003, of a $100 investment in Trust Units with the cumulative total return of the S&P/TSX Composite Index and the TSX Oil & Gas Producers Index, assuming the reinvestment of dividends/distributions, where applicable, for the comparable period.

The Total Unitholder Return is shown in the following graph. Details of the distributions are as follows:

Payment Period	Amount
January 1 to December 31, 1998	$1.840
January 1 to December 31, 1999	$1.555
January 1 to December 31, 2000	$1.900
January 1 to December 31, 2001	$3.045
January 1 to December 31, 2002	$1.800
January 1 to December 31, 2003	$2.180
TOTAL	$12.320

INDEX	DEC. 31/97	DEC. 31/98	DEC. 31/99	DEC. 31/00	DEC. 31/01	DEC. 31/02	DEC. 31/03
APF Energy Trust Total Return	100%	113%	132%	198%	266%	314%	489%
S & P/TSX Composite Index Total Return	100%	98%	130%	139%	122%	107%	135%
TSX Oil & Gas Producers Index Total Return	100%	70%	85%	125%	129%	150%	181%

Total Return Index Values



Summary Compensation Table

The following table shows the total compensation paid by APF to each Named Executive Officer during each of the three most recently completed financial years.

Name and Principal Position	Annual Compensation				Long Term Compensation	All Other Compensation
	Year[1]	Salary ($)	Bonus[2] ($)	Other Annual Compensation ($)	Securities Under Options/SARs Granted	
Martin Hislop Chief Executive Officer	2003	248,000	197,117	Nil	101,344	Nil
Steven Cloutier President	2003	248,000	197,117	Nil	101,344	Nil
Bonnie Nicol Vice-President, Operations	2003	168,000	133,531	Nil	69,493	Nil
Alan MacDonald Vice-President, Finance	2003	168,000	133,531	Nil	69,493	Nil
Kenneth Pretty Vice-President, Corporate Development and Land	2003	168,000	133,531	Nil	69,493	Nil
John Ewing Vice-President, Geoscience	2003	168,000	133,531	Nil	69,493	Nil

Notes:

(1) Compensation is provided only for the year ended December 31, 2003, the year in which the management of the Trust was internalized. Prior thereto, no compensation payments were made to the Named Executive Officers by the Trust or APF, as they were compensated by APF Energy Management Inc., the Manager of the Trust.

(2) The bonus amounts were paid under the "Group Bonus", as described above, for the year ended December 31, 2003. The amounts do not include payments made in 2004 for the "Performance Bonus", as described above. The Performance Bonus paid in 2004 is subject to APF Board of Director approval in 2004 and will be included as compensation for the year ended December 31, 2004.

(3) The value of perquisites and benefits for each Named Executive Officer is less than the lesser of $50,000 and 10% of the total of the annual salary and bonus of the Named Executive Officer for the financial year.

Options/SAR Grants During the Most Recently Completed Financial Year

The option and SAR grants made to each of the Named Executive Officers during the most recent financial year are set forth in the following table:

Name	Securities under Options/SARs Granted (#)	% of Total Options/SARs Granted to Employees in Financial Year	Exercise or Base Price[1] ($/Security)	Market Value of Securities Underlying Options/SARs on the Date of the Grant ($/Security)	Expiration Date
Martin Hislop	101,344 Rights	6.6%	9.67	9.67	2013/04/06
Steven Cloutier	101,344 Rights	6.6%	9.67	9.67	2013/04/06
Bonnie Nicol	69,493 Rights	4.5%	9.67	9.67	2013/04/06
Alan MacDonald	69,493 Rights	4.5%	9.67	9.67	2013/04/06
Kenneth Pretty	69,493 Rights	4.5%	9.67	9.67	2013/04/06
John Ewing	69,493 Rights	4.5%	9.67	9.67	2013/04/06

Note:

(1) Holders of rights can elect to reduce the exercise price of their rights in future periods by a portion of the future distributions made by the Trust. See "Trust Unit Incentive Plan and Trust Unit Incentive Rights Plan" below.

Trust Unit Option and Right Exercises

The following table sets forth with respect to the Named Executive Officers, the number of Trust Units acquired on exercise of options and rights during the year and the Unexercised Trust Unit Options/Rights and the Value of in-the-Money Trust Unit Option/Rights at December 31, 2003.

Name	Securities Acquired or Exercised (#)	Aggregated Value Realized ($)	Unexercised Trust Unit Options/Rights/SARs at FY-End (#) Exercisable/ Unexercisable	Value of Unexercised in-the-Money Options/Rights/SARs at FY-End [1] ($) Exercisable/ Unexercisable
Martin Hislop	26,700	112,985	38,333 / 133,011	108,617 / 380,291
Steven Cloutier	16,000	72,800	32,633 / 124,211	104,209 / 355,399
Bonnie Nicol	11,444	23,058	0 / 82,603	0 / 236,477
Alan MacDonald	6,780	7,729	4,887 / 92,826	13,732 / 265,012
Kenneth Pretty	13,333	21,333	5,000 / 92,827	14,050 / 265,413
John Ewing	0	0	0 / 69,493	0 / 199,445

Notes:

(1) The closing price of the Trust Units on the TSX on December 31, 2003 was $12.54.

(2) Rights holders can elect to reduce the exercise price of their rights in future periods by a portion of the future distributions (the "reduction feature") in accordance with the Rights Plan. See "Trust Unit Incentive Plan and Trust Unit Incentive Rights Plan" below. The reduction feature reduces the exercise price by the amount, if any, that cash distributions in any calendar quarter exceed 2.5% of APF's net book value of property, plant and equipment. The above values for unexercised in-the-money options assume that no such election for reduction is exercised.

REMUNERATION OF DIRECTORS OF APF

For the year ended December 31, 2003, the Chairman of APF was paid an annual retainer of $50,000 and $2,000 per board and committee meeting attended, plus expenses of attending such meetings. Each of the other non-management directors of APF received an annual retainer of $35,000. Payment for attendance at meetings and expenses of attending such meetings were payable on the same basis as for the Chairman. In the fiscal year of the Trust ended December 31, 2003, a total of $223,000 in fees was paid to the non-management directors of APF.

In addition, for serving on the Special Committee on the internalization of the management contract, the Chairman was paid a retainer of $10,000 and $1,000 per meeting attended, and each of the other non-management directors were paid a retainer of $5,000 and $1,000 per meeting attended, for total fees of $91,000.

INDEBTEDNESS OF DIRECTORS AND SENIOR OFFICERS AND OTHERS

There is not now, nor was there any indebtedness outstanding from Directors or Officers of APF to the Trust or APF at any time in the last fiscal year.

TRUST UNIT INCENTIVE PLAN AND TRUST UNIT INCENTIVE RIGHTS PLAN (the "Original Plan" and "Incentive Rights Plan" respectively)

At the time of creation of the Trust, the Board of Directors of APF approved a trust unit incentive plan for Directors, Officers, employees and consultants of APF. The number of options and the exercise price thereof is set by the Board of Directors of APF at the time of grant provided that the exercise price shall not be less than the closing market price of the Trust Units on the day immediately preceding the date of grant. Options granted under the Original Plan may be exercised during a period not exceeding five years, subject to earlier termination upon an optionee ceasing to be a Director, Officer, employee or consultant of APF or upon an optionee retiring, becoming permanently disabled or dying. The options are non-transferable and non-assignable. No further options will be granted under the Original Plan.

By resolution of the Board of Directors of APF effective February 1, 1998, the Original Plan was amended to provide that, in lieu of immediate vesting, options shall vest as to one-third in the year following the anniversary date of the grant and as to a further one-third in each of the second and third years following the anniversary date of the grant.

There are currently options to purchase 113,536 Trust Units issued and outstanding under the Original Plan. They are granted at prices from $7.15 to $9.70 and expire between March, 2005 and March, 2006. No new options will be granted.

On June 6, 2001, the Unitholders approved the creation of the Incentive Rights Plan and it has been implemented by the Board of Directors.

At present, the Incentive Rights Plan has a maximum of 2,600,000 Trust Units. The number of rights and the exercise price is set by the Board of Directors of APF at the time of grant, provided that the exercise price shall not be less than the closing market price of the Trust Units on the day immediately preceding the date of grant.

Distributions per Trust Unit to Unitholders in a calendar quarter which represent a return of more than 2.5% of the Trust's net book capital assets at the end of such calendar quarter result in a downward reduction in the exercise price of the rights at the election of the holder of rights by notice to APF at the time of exercise of the right. The Incentive Rights Plan will be administered by the Board of Directors who may also vary the 2.5% threshold from time to time to accord with their view of the economic environment, establish a minimum price for the issuance of Trust Units on the exercise of the rights and extend the exercise period of any rights to a period not exceeding ten years.

Rights granted under the Incentive Rights Plan may be exercised during a period not exceeding ten years, subject to earlier termination upon a holder of rights ceasing to be a Director, Officer, employee or a consultant of APF. The rights are non-transferable and non-assignable. The rights vest over a three-year period, with one-third of the rights vesting at the end of each year, and under certain other limited circumstances.

There are currently rights to purchase 2,180,002 Trust Units granted under the Incentive Rights Plan. They were granted at prices from $9.67 to $12.17 and expire between March, 2012 and March, 2014. See "Matters to be Acted Upon at the Meeting - The Trust Unit Incentive Rights Plan Amendment".

CORPORATE GOVERNANCE

General

The Board of Directors continually evaluates the corporate governance policies and procedures of the Corporation. In 2003, the Board of Directors appointed one new Director to the Board who was also appointed to the Audit Committee (and the Reserves Committee) and who qualifies through education, training and experience as being "financially literate", and accepted the resignation of one management Director as a committee member. The Audit Committee is now comprised entirely of unrelated Directors.

Corporate Governance Guidelines

APF's Board of Directors and management support the TSX Guidelines for corporate governance. The approach taken by APF, on behalf of the Trust to corporate governance and compliance with the Guidelines is as follows:

Corporate Governance Guidelines	The Trust's Alignment	Comments
1. The Board should explicitly assume responsibility for stewardship and specifically for:	Yes	The Board of Directors of APF (the "Board") expressly accepts responsibility for the stewardship of the Trust to the extent delegated to APF under the Trust Indenture. In general terms, the Board, in consultation with the chief executive officer of APF (the "CEO"), defines the principal objectives of the Trust and monitors the management of the business and affairs of the Trust with the goal of achieving the Trust's principal objectives.
(a) adoption of a strategic planning process	Yes	A strategic planning process has been adopted by the Board. Each year, the Board meets to review APF's business and operations in the context of broader industry and capital market developments. Given the rapid growth of APF's asset base, the Board supplements these annual meetings with bi-annual meetings where senior management provide detailed information and analysis on APF's past performance, current initiatives and anticipated projects. The plan is reviewed annually once APF's independent engineering report is finalized and its operating and financial results have been released.
(b) identification of principal risks and the implementation of appropriate risk-management systems	Yes	The Board has identified the principal risks of APF and the Trust. Risk-management systems have been implemented and are monitored, by the Audit Committee in respect of internal financial controls, and the Board as a whole for other aspects of the business, such as commodity, foreign exchange and interest rate risks.
(c) succession planning and monitoring senior management	Yes	The Board has established succession planning as one of the objectives of the CEO. The performance of senior management is currently monitored by the Board.
(d) communications policy	Yes	The Board has designated the President, the CEO and the Vice President, Finance as spokesmen for the Trust to ensure effective communication between the Trust, Unitholders, the public and regulatory agencies. The Audit Committee reviews public financial information for recommendation to the Board for approval prior to its release.

Corporate Governance Guidelines	The Trust's Alignment	Comments
(e) integrity of internal control and management information systems	Yes	The Board ensures the integrity of internal control and management information systems through its delegation to the Audit Committee. The Audit Committee reviews the methods of controlling corporate assets and information systems and oversees the financial reporting process in accordance with generally accepted accounting principles.
2. Majority of directors are unrelated and how the conclusion was reached	Yes	Of the six present directors, four are unrelated. The unrelated directors comply with the definition in the Guidelines, which define an unrelated director as a director who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the Trust, other than interests arising from securityholdings. The Chairman of the Board is one of the unrelated directors.
3. Appoint a committee responsible for appointment/assessment of directors, composed of a majority of unrelated directors	Yes	A committee has not been appointed, these duties are currently being undertaken generally by the Board and specifically by the Chairman, who is unrelated to management.
4. Implement a process for assessing the effectiveness of the Board, its committees and individual directors	Yes	The Board performs this function on an ongoing basis with the assistance of such outside consultants as are required.
5. Provide orientation and education programs for new directors	Yes	All current Board members are provided with regular information specific to APF, as well as continuing education material that touches on a number of relevant topics, such as: commodity markets; risk management; and corporate governance.
6. Consider the size of the Board, with a view to improving effectiveness	Yes	The present Board consists of six members, which the Board considers to be appropriate given the size of the Trust. The Board will assess, from time to time, whether further expansion is warranted.

Corporate Governance Guidelines	The Trust's Alignment	Comments
7. Review compensation of directors in light of risks and responsibilities	Yes	Effective January 1, 2003, the compensation of the unrelated Directors was adjusted to reflect increased risks and responsibilities. The quantum was determined in the context of compensation rates for Directors of similarly sized public entities, as well as on data provided by an independent compensation consultant. This represented the first adjustment since the Trust's inception in 1996. The Board will assess, from time to time, whether further adjustments are warranted, having reference again to compensation rates for Directors of similarly sized public entities, as well as on data provided by an independent compensation consultants.
8. Committees should generally be composed of non-management directors; and the majority of committee members should be unrelated	Yes	The Audit Committee and Reserves Committee are composed entirely of unrelated Directors. The Compensation Committee is currently composed of a majority of unrelated Directors. It is intended that, following the Meeting, the Compensation Committee will be constituted entirely of unrelated Directors.
9. Appoint a committee responsible for determining the Corporation's approach to corporate governance issues	Yes	The Audit Committee is currently responsible for governance issues, including recommending to the Board for approval the Trust's disclosures in response to the TSX governance guidelines.
10. Define limits to management's responsibilities by developing mandates for:	Yes	
(a) the Board	Yes	The Board has a broad responsibility for supervising the management of the business and affairs of APF. It has the statutory authority and obligation to protect and enhance the assets of APF in the interest of all Unitholders.
(b) the Chief Executive Officer The Board should approve the Chief Executive Officer's corporate objectives	Yes	The annual business plan based on the strategic plan is reviewed by the Board annually and updated at regular Board meetings. Upon approval, this becomes the mandate of the CEO and President.
11. Establish procedures to enable the Board to function independently of management	Yes	Through the office of the Chairman, who is unrelated to management, the independent members of the Board may initiate discussions and proposals for consideration by the Board as a whole.

Corporate Governance Guidelines	The Trust's Alignment	Comments
12. Establish an Audit Committee with a specifically defined mandate, with all members being outside directors	Yes	The Audit Committee, which is composed entirely of outside and unrelated Directors, has a written mandate from the Board. It is responsible for reviewing audit functions and recommending for approval to the Board all public disclosure information such as financial statements, quarterly reports, financial news releases and annual information forms. It makes inquiries to ensure that management has effective internal control systems in place and meets with the auditors with and without management present.
13. Implement a system to enable individual directors to engage outside advisors at the Corporation's expense	Yes	Individual Directors may engage outside advisors at any time subject to the approval of the Chairman.

DISTRIBUTION REINVESTMENT PLAN

On November 20, 2003, the Trust announced the adoption of a Premium Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003.

The DRIP allows eligible Unitholders to direct that their monthly cash distributions be reinvested in additional Trust Units at 95% of the average market price (as defined in the DRIP) on an applicable distribution date. The DRIP includes a feature which allows eligible Unitholders to elect, under the premium distribution component of the DRIP, to have these additional Trust Units delivered to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such Unitholders would have otherwise been entitled to receive on the applicable distribution date. The DRIP also allows those Unitholders who participate in either the distribution reinvestment component or the premium distribution component of the DRIP to purchase additional Trust Units from treasury for cash at a purchase price equal to the average market price (with no discount) in minimum amounts of $1,000 per remittance and up to $100,000 aggregate amount of remittances by a Unitholder in any calendar month, all subject to an overall annual limit of 2% of the outstanding Trust Units.

No Trust Units have, to date, been issued from treasury of the Trust on account of the DRIP.

A participant may terminate participation in the DRIP at any time by written notice to the DRIP Agent, being Computershare Trust Company of Canada, 9th Floor, 100 University Avenue, Toronto, Ontario M5J 2Y1.

INTEREST OF INSIDERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of Directors and senior Officers of APF, nominees for Director of APF, any Unitholder who beneficially owns more than 10% of the Trust Units of the Trust, or any known associate or affiliate of such persons in any transaction in the year ending December 31, 2003, or in any proposed transaction which has materially affected or would materially affect the Trust or APF other than as disclosed herein, except with respect to the internalization of management, which was described in the information circular of the Trust dated November 18, 2002.

INTEREST OF CERTAIN PERSONS AND COMPANIES IN MATTERS TO BE ACTED UPON

APF is not aware of any material interest of any Director, nominee for Director or Officer of APF or any one who has held office as such in the year ending December 31, 2003, or of any associate or affiliate of any of the foregoing in respect of any matter to be acted on at the Meeting, except as specifically provided herein.

OTHER MATTERS

APF knows of no amendment, variation or other matter to come before the Meeting other than the matters referred to in the Notice of Annual General and Special Meeting. However, if any other matter properly comes before the Meeting, the accompanying proxy will be voted on such matter in accordance with the best judgment of the person or persons voting the proxy.

APPROVAL AND CERTIFICATION

The contents and sending of this Information Circular - Proxy Statement have been approved by the Board of Directors of APF on behalf of the Trust.

The foregoing contains no untrue statement of a material fact and does not omit to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made.

DATED April 2, 2004

APF ENERGY TRUST
By: APF Energy Inc.

(Signed) *"Martin Hislop"*
Chief Executive Officer

(Signed) *"Alan MacDonald"*
Chief Financial Officer

SCHEDULE "A"

A. Trustee Re-Appointment Resolution

BE IT RESOLVED THAT Computershare Trust Company of Canada be appointed as the Trustee of the Trust, until the termination of the Trust or until the Trustee resigns or is removed or replaced, in accordance with the provisions of the trust indenture by which the Trust was established.

B. Trust Unit Incentive Rights Plan Amendment Resolution

BE IT RESOLVED THAT:

1. The Trust Unit Incentive Rights Plan be amended, as described in the Information Circular of the Trust dated April 2, 2004, to increase the maximum number of Trust Units issuable under the Plan from 2,600,000 to 3,200,000.

2. Any Director or Officer of APF be and is hereby authorized, for and on behalf of the Trust, to execute and deliver such documents and instruments and take such other actions as such Director or Officer may determine to be necessary or advisable to implement this resolution and the matters authorized hereby, such determination to be conclusively evidenced by the execution and delivery of any such documents or instruments and the taking of any such actions.

C. Trust Indenture Amendment Resolution

BE IT RESOLVED AS A SPECIAL RESOLUTION THAT:

1. The Trust Indenture between APF and Computershare Trust Company of Canada on behalf of the Trust be and it is hereby amended to delete the first sentence of Section 16.2 and Section 16.3(a) of the Trust Indenture.

2. The Trustee and the Board of Directors of APF be and they are hereby authorized to settle the form of the amendments to the Trust Indenture in accordance with the foregoing resolution and to effect all such further or consequential amendments to the Trust Indenture and other relevant agreements as they may consider necessary or desirable to give effect to and fully carry out the intent of the foregoing resolutions.

D. ***Royalty Agreements Amendment Resolution***

BE IT RESOLVED AS A SPECIAL RESOLUTION THAT:

1. The definitions of "Asset Value", "Proved Reserves" and "Probable Reserves" contained in Section 1.1 of the Royalty Agreements be amended, as described in the Information Circular of the Trust dated April 2, 2004 to be consistent with the new definitions of proved reserves and probable reserves contained in National Instrument 51-101.

2. The Trustee and the Board of Directors of APF be and they are hereby authorized to settle the form of the amendments to the Royalty Agreements in accordance with the foregoing resolution and to effect all such further or consequential amendments to the Royalty Agreements and other relevant agreements of APF and the Trust as they may consider necessary or desirable to give effect to and fully carry out the intent of the foregoing resolution.

RECEIVED
2004 APR 26 P 12: 10
OFFICE OF INTERNATIONAL CORPORATE FINANCE

APF ENERGY TRUST
(the "Trust")

Instrument of Proxy

For the Annual General and Special Meeting of Unitholders

The undersigned holder of trust units ("Units") of the Trust hereby appoints Martin Hislop, Chief Executive Officer and a director of APF Energy Inc. ("APF Energy") of the City of Calgary, in the Province of Alberta, or, failing him, Steven Cloutier, Secretary, President, Chief Operating Officer and a director of APF Energy of the City of Calgary, in the Province of Alberta, or instead of either of the foregoing, ____________, as proxyholder of the undersigned, with full power of substitution, to attend and act and vote for and on behalf of the undersigned at the Annual General and Special Meeting (the "Meeting") of the Unitholders of the Trust, to be held on May 18, 2004, and at any adjournment or adjournments thereof and on every ballot that may take place in consequence thereof to the same extent and with the same powers as if the undersigned were personally present at the Meeting with authority to vote at the said proxyholders' discretion, except as otherwise specified below.

Without limiting the general powers hereby conferred, the undersigned hereby directs the said proxyholder to vote the Units represented by this instrument of proxy in the following manner:

1. **FOR** ☐ **or WITHHOLD FROM VOTING FOR** ☐ the selection of six (6) Directors of APF Energy and to fix the number of Directors for the forthcoming year at six, as specified in the Information Circular - Proxy Statement of the Trust dated April 2, 2004;

2. **FOR** ☐ **or WITHHOLD FROM VOTING FOR** ☐ the appointment of PricewaterhouseCoopers LLP, Chartered Accountants, as auditors of the Trust for the ensuing year and to authorize the Board of Directors of APF Energy to fix the remuneration of the auditors;

3. **FOR** ☐ **or AGAINST** ☐ a resolution to approve the re-appointment of Computershare Trust Company of Canada as trustee of the Trust for the ensuing year, as more particularly described in the Information Circular – Proxy Statement of the Trust dated April 2, 2004;

4. **FOR** ☐ **or AGAINST** ☐ a resolution approving the increase in the maximum number of Trust Units issuable under the Trust Unit Incentive Rights Plan of the Trust, as more particularly described in the Information Circular – Proxy Statement dated April 2, 2004;

5. **FOR** ☐ **or AGAINST** ☐ a special resolution to amend the trust indenture between APF Energy and Computershare Trust Company of Canada as trustee of the Trust, to delete the requirement that unaudited quarterly financial statements and audited annual financial statements must be mailed to each Unitholder, as more particularly described in the Information Circular – Proxy Statement dated April 2, 2004;

6. **FOR** ☐ **or AGAINST** ☐ a special resolution to amend the royalty agreements, by which a royalty is granted to the Trust by each of APF Energy and APF Energy Limited Partnership, to amend the definitions of "Asset Value", "proved reserves" and "probable reserves", to make the definitions consistent with National Instrument 51-101, as more particularly described in the Information Circular – Proxy Statement of the Trust dated April 2, 2004;

7. At the discretion of the said proxyholders, upon any amendment or variation of the above matters or any other matter that may be properly brought before the Meeting or any adjournment thereof in such manner as such proxyholder, in such proxyholder's sole judgment, may determine.

This Instrument of Proxy is solicited by the management of APF Energy on behalf of the Trust, pursuant to authority delegated to it by the Trust. The Units represented by this Instrument of Proxy will be voted and, where the Unitholder has specified a choice with respect to the above matters, will be voted as directed above or, if no direction is given, will be voted in favour of the above matters. Each Unitholder has the right to appoint a proxyholder, other than the persons designated above, who need not be a Unitholder, to attend and to act for him and on his behalf at the Meeting. To exercise such right, the names of the nominees of management should be crossed out and the name of the Unitholder's appointee should be legibly printed in the blank space provided.

The undersigned hereby revokes any proxies heretofore given.

Dated this ____ day of ______________, 2004.

____
Signature of Unitholder

____
Name of Unitholder - (please print)

NOTES:

1. If the Unitholder is a corporation, its corporate seal must be affixed or it must be signed by an officer or attorney thereof duly authorized.

2. This form of proxy must be dated and the signature hereon should be exactly the same as the name in which the Units are registered. If this proxy is not dated, it shall be deemed to bear the date on which it was mailed.

3. Persons signing as executors, administrators, trustees, etc., should so indicate and give their full title as such.

4. This instrument of proxy will not be valid and not be acted upon or voted unless it is completed as outlined herein and delivered to the attention of Computershare Trust Company of Canada, Attention: Proxy Department, 9th Floor, 100 University Avenue, Toronto, Ontario M5J 2Y2 not less than 24 hours before the time set for the holding of the Meeting or any adjournment thereof. A proxy is valid only at the meeting in respect of which it is given or any adjournment(s) of that Meeting.

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the consolidated financial statements and the preparation of all other financial information included in the annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, and where applicable, amounts based on management's best estimates and judgment.

Management has established procedures and systems of internal control designed to provide reasonable assurance that assets are safeguarded and that accurate financial information is produced in a timely manner.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and, through its Audit Committee, ensuring that management fulfills its responsibilities for financial reporting. The Audit Committee meets periodically with management and the external auditors to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors. PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, appointed by the unitholders of APF Energy Trust, have audited the consolidated financial statements in accordance with Canadian generally accepted auditing standards. PricewaterhouseCoopers LLP have full and free access to the Audit Committee.

Martin Hislop
Chief Executive Officer

Alan MacDonald
Vice President, Finance

Calgary, Alberta
February 20, 2004

Auditors' Report

To the Unitholders of APF Energy Trust

We have audited the consolidated balance sheets of APF Energy Trust as at December 31, 2003 and 2002 and the consolidated statements of operations and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust'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 Trust 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.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta
February 20, 2004

Consolidated Balance Sheets

As at December 31	2003	2002
	($000)	($000)
ASSETS		
Current assets		
Cash	**1,381**	950
Accounts receivable	**27,542**	21,111
Other current assets	**3,506**	2,779
	32,429	24,840
Site restoration fund (note 6)	**2,342**	784
Goodwill (note 7)	**48,230**	11,476
Property, plant and equipment (note 5)	**401,286**	260,527
	484,287	297,627
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**36,711**	16,943
Due to APF Energy Management Inc. (note 14)	**–**	3,923
Cash distribution payable	**5,963**	3,565
	42,674	24,431
Future income taxes (note 13)	**64,222**	39,625
Long-term debt (note 8)	**98,000**	88,000
Site restoration liability (note 6)	**10,410**	6,227
	215,306	158,283
UNITHOLDERS' EQUITY		
Unitholders' investment account (note 9)	**324,317**	214,405
Contributed surplus (note 10)	**1,241**	–
Accumulated earnings	**78,637**	35,589
Accumulated cash distributions (note 4)	**(179,363)**	(110,650)
Convertible debentures (note 12)	**46,466**	–
Accumulated interest on convertible debentures	**(2,317)**	–
	268,981	139,344
	484,287	297,627

Contingencies and commitments (note 17)

See accompanying notes to consolidated financial statements

Approved by the Board of Directors

Don Engle
Director

Martin Hislop
Director

Consolidated Statements of Operations and Accumulated Earnings

For the years ended December 31	2003	2002
	($000)	($000)
Revenue		
Oil and gas	**163,532**	92,345
Royalties expense, net of ARTC	**(32,473)**	(18,707)
Other	**1,925**	1,676
	132,984	75,314
Expenses		
Operating	**32,370**	19,748
General and administrative (note 14)	**10,023**	4,635
Stock-based compensation expense (note 10)	**1,241**	-
Management fee (note 14)	**–**	1,976
Interest on long-term debt	**4,171**	2,834
Depletion, depreciation and amortization	**50,417**	30,201
Site restoration	**3,327**	2,087
Capital and other taxes	**2,720**	1,901
Internalization of management contract (note 14)	**–**	7,297
	104,269	70,679
Income before income taxes and minority interest	**28,715**	4,635
Recovery of future income taxes (note 13)	**14,333**	7,133
Income before minority interest	**43,048**	11,768
Minority interest (note 14)	**–**	403
Net income	**43,048**	11,365
Accumulated earnings – beginning of year	**35,589**	24,224
Accumulated earnings – end of year	**78,637**	35,589
Net income per unit – basic ($)	**1.32**	0.55
Net income per unit – diluted ($)	**1.21**	0.55

See accompanying notes to consolidated financial statements

Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the years ended December 31	2003 ($000)	2002 ($000)
CASH PROVIDED BY (USED IN)		
Operating activities		
Net income for the year	**43,048**	11,365
Items not affecting cash		
Depletion, depreciation and amortization	**50,417**	30,200
Minority interest	**–**	403
Future income taxes	**(14,333)**	(7,133)
Internalization of management contract	**–**	7,037
Stock-based compensation expense	**1,241**	–
Site restoration	**3,327**	2,087
Site restoration expenditures (note 6)	**(374)**	(171)
	83,326	43,788
Net change in non-cash working capital items		
Accounts receivable	**1,016**	(7,994)
Other current assets	**(398)**	(328)
Accounts payable and accrued liabilities	**9,138**	6,537
Due to related party / APF Management	**(3,923)**	(1,088)
Cash distribution payable	**2,398**	1,227
	8,231	(1,646)
Site restoration fund contribution	**(1,558)**	(754)
Cash distributions	**(68,713)**	(37,766)
	21,286	3,622
Investing activities		
Purchase of Hawk Oil	**(3,456)**	–
Purchase of Nycan Energy	**(34,287)**	–
Purchase of CanScot Resources	**(20,516)**	–
Purchase of Kinwest	**–**	(17,361)
Additions to property, plant and equipment	**(33,601)**	(20,979)
Purchase of oil and natural gas properties	**(29,238)**	(28,574)
Proceeds on sale of properties	**9,284**	10,569
Changes in non-cash working capital-investing items	**2,961**	(560)
	(108,853)	(56,905)
Financing activities		
Issue of units for cash	**57,272**	32,250
Issue of units for cash upon exercise of stock options	**1,749**	554
Unit issue costs	**(3,467)**	(1,861)
Convertible debentures – net of costs	**47,681**	–
Interest on convertible debentures	**(2,317)**	–
(Repayment)/proceeds on issue of long-term debt – net	**(12,920)**	21,650
Distribution to 1% minority interest	**–**	(403)
	87,998	52,190
Change in cash during the year	**431**	(1,093)
Cash – beginning of year	**950**	2,043
Cash – end of year	**1,381**	950
Supplemental information (note 16)		

See accompanying notes to consolidated financial statements

The objective and integrity of data in these financial statements, including estimates and judgements relating to matters not concluded by year-end, are the responsibility of management of APF Energy Trust ("Trust"). In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies.

NOTE 1 BASIS OF PRESENTATION

APF Energy Trust (the "Trust")
The Trust is an open-end investment trust under the laws of the Province of Alberta.

APF Energy Inc. ("Energy")
Energy was incorporated and organized for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties, including certain initial properties and granting a royalty thereon to the Trust.

APF Energy Limited Partnership ("LP")
LP was formed for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties and granting a royalty thereon to the Trust.

Tika Energy Inc. ("Tika")
Tika is a wholly owned subsidiary of Energy and was incorporated in Wyoming for the purpose of acquiring, developing, exploiting and disposing of coalbed methane gas properties in the United States.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Consolidation
These consolidated financial statements include the accounts of the Trust, Energy, LP and Tika and are referred to collectively as "APF".

Revenue recognition
Revenue associated with the sale of crude oil, natural gas, and natural gas liquids owned by the Trust are recognized when title passes from the Trust to its customers.

Goodwill
The Trust records goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or as events occur that could indicate an impairment. Impairment is recognized based on the fair value of APF compared to the net book value of APF. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Property, plant and equipment – oil and natural gas
APF follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in a cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements, which extend the economic life of the property, plant and equipment are capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more.

Ceiling test
The Trust places a limit on the aggregate carrying value of property, plant and equipment. An impairment is recognized if the carrying amount of the property, plant and equipment exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

The Trust determines if there is an impairment by comparing the carrying amounts of the property, plant and equipment to an amount equal to the fair value of the property, plant and equipment. Any excess carrying value above the fair value of the Trust's future cash flows would be recorded as a permanent impairment. The cost of unproved properties are excluded from the ceiling test calculation and is subject to a separate impairment test.

Depletion, depreciation and amortization

Depletion, depreciation and amortization of oil and natural gas assets including tangible equipment is calculated using the unit-of-production method based on the working interest share of total proven reserves before royalties. Reserves estimates are calculated in accordance with National Instrument 51-101 and relative volumes of petroleum and natural gas reserves and production, before royalties are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Site restoration and abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method. Actual site restoration costs are charged against the accumulated provision.

Other equipment

All other equipment is carried at cost and is depreciated over the estimated useful life of the assets at annual rates varying from 10% to 30%.

Joint ventures

Substantially all oil and natural gas production and exploitation activities are conducted jointly with others. Accordingly, the accounts reflect APF's proportionate interest in these activities.

Trust per unit calculations

The Trust has applied the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

Cash distributions declared per unit amount are based on actual distribution for units outstanding at the time of declaration.

Unit based compensation

APF has established a Trust Unit Incentive Rights Plan (the "Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of APF. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to unitholders to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the financial statements for unexercised rights.

The Trust has a Trust Unit Incentive Rights Plan which is described in note 10.

Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in earnings in the period of change with a corresponding increase or decrease in contributed surplus. This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying Trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights exercised or outstanding at the date of the financial statements.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital. If Trust Units or Trust Unit options are repurchased from employees, the excess of the consideration paid over the carrying amount of the Trust Units or Trust Unit options cancelled is charged to accumulated earnings.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, APF accounts for actual forfeitures as they occur.

Cash distributions
Cash distributions are calculated on an accrual basis and are paid to the Unitholders based upon funds available for distribution.

Income taxes
The Trust is an inter vivos trust for income tax purposes. As such, the Trust is taxable on any taxable income which is not allocated to the Unitholders. The Trust intends to allocate all taxable income to Unitholders. Should the Trust incur any income taxes, the funds available for distribution will be reduced accordingly. Provision for income taxes is recorded in Energy at applicable statutory rates. Provision for income taxes is recorded in Energy using the liability method of accounting whereby the future income tax effect of any difference between the accounting and income tax basis of an asset or liability is booked.

Management estimates
The consolidated financial statements include certain management estimates that may require accounting adjustments based on future occurrences. The most significant estimates relate to depletion, depreciation and amortization and ceiling test calculations for capital assets including future abandonment liabilities as they are based on engineering reserve estimates and estimated future costs.

NOTE 3 CHANGE IN ACCOUNTING POLICIES

Accounting Guideline 16
Effective December 2003, the Trust adopted AcG-16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants which replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry".

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

Stock based compensation
APF elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, APF must account for compensation expense based on the fair value of rights granted under its' unit-based compensation plan. As APF is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the grant date or at the date of the financial statements for unexercised rights as described in Note 2.

For rights granted in 2002, APF has elected to disclose pro forma results as if the amended accounting standard had been adopted retroactively. As a result of adopting this standard, net income for the year ended December 31, 2003 decreased by $1.2 million and contributed surplus increased by $1.2 million.

See Note 10 for additional information regarding the nature of the plan and the associated compensation expense.

NOTE 4 CASH DISTRIBUTIONS AND ACCUMULATED CASH DISTRIBUTIONS

The following table is the calculation of cash distributions and accumulated cash distributions:

($000, except per unit amounts)	2003	2002
	$000	$000
Oil and gas sales	**163,532**	92,345
Other	**1,925**	1,676
Gross overriding royalties and lessors' royalties	**(13,109)**	(7,802)
	152,348	86,219
Less		
Operating costs	**32,370**	19,748
General and administrative	**9,362**	4,317
Management fees	**–**	1,976
Debt service charges (including interest and principal)	**4,171**	2,834
Site restoration fund contribution	**1,932**	925
Capital and other taxes	**2,720**	1,901
Capital expenditures funded from cash flow	**9,326**	5,144
	59,881	36,845
Income subject to the royalty	**92,467**	49,374
99% of income subject to the royalty	**91,542**	48,880
Crown charges, net of Alberta Royalty Tax Credit	**(19,851)**	(10,796)
Interest on convertible debentures	**(2,317)**	–
General and administrative costs of the Trust	**(661)**	(318)
Cash available to be distributed	**68,713**	37,766
Cash distributed to date	**62,750**	34,201
Cash distribution payable	**5,963**	3,565
Actual cash distribution declared per unit ($)	**2.195**	1.810
Opening accumulated cash distributions	**110,650**	72,884
Distribution declared and paid	**62,750**	34,201
Distribution declared and payable	**5,963**	3,565
Closing accumulated cash distributions	**179,363**	110,650

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

($000)	2003	2002
Property, plant and equipment	**531,365**	340,189
Accumulated depletion, depreciation and amortization	**(130,079)**	(79,662)
	401,286	260,527

The calculation of 2003 depletion, depreciation and amortization included an estimated $25.0 million (2002 – $16.7 million) for future development costs associated with proved undeveloped reserves and excluded $10.8 million (2002 – $7.9 million) for the estimated value of unproved properties and coalbed methane projects currently in the development stage. General and administration costs of $458,000 associated with coalbed methane projects have been capitalized (2002 – $nil).

The Trust performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of property, plant and equipment. The crude oil and natural gas futures prices are management's best estimates and are based on information obtained from third parties and were adjusted for commodity differentials specific to the Trust. Future prices were obtained for the period of 2004 to 2008 inclusive and then escalated based on escalation factors in the Trust's year-end independent reserves evaluation.

Based on these assumptions, which are shown below, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's property, plant and equipment at December 31, 2003.

Year	WTI Oil ($U.S./bbl)	Foreign exchange rate ($U.S./$Cdn.)	WTI Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2004	30.18	0.77	39.43	5.72
2005	27.44	0.76	36.12	5.42
2006	26.67	0.75	35.33	5.27
2007	26.61	0.75	35.43	5.23
2008	26.78	0.75	35.77	5.18
2009 – 2014 (1)	–			–
Remainder (2)	1.5%			1.5%

(1) Percentage change represents the average for the period noted.

(2) Percentage change represents the change in each year after 2014 to the end of the reserve life.

NOTE 6 SITE RESTORATION FUND/LIABILITY

Energy and the LP are responsible for future site restoration costs on all properties. At December 31, 2003 the future undiscounted estimated costs for the site restoration liabilities were $31,198,000 (2002 – $29,858,000), of which $10,410,000 has been provided for. The current year expense charged to the provision was $3,327,000 (2002 – $2,087,000). Actual payments for abandonment in 2003 were $374,000 (2002 – $171,000).

A site restoration fund was established to fund future site reclamation and abandonment costs. Contributions to the site restoration fund during the year totalled $1,932,000 (2002 – $925,000) and have been deducted in calculating the income subject to the royalty.

Contributions to the site restoration fund are determined annually by management and are based on the average of the next three years expected site restoration expenses, as determined by the independent engineers.

NOTE 7 ACQUISITIONS

Effective February 5, 2003, Energy acquired all of the issued and outstanding shares of Hawk Oil Inc. ("Hawk Oil"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Bank overdraft	(5)
Other working capital	(629)
Property, plant and equipment	57,146
Goodwill	11,078
Debt assumed	(7,900)
Site restoration liability	(263)
Future income taxes	(18,266)
Total net assets acquired	41,161
Financed by	
Cash	2,856
Trust units issued (3,990,461 Trust units)	37,710
Acquisition costs	595
Total consideration	41,161

Effective April 28, 2003, Energy acquired all of the issued and outstanding shares of Nycan Energy Corp. ("Nycan"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Cash	212
Other working capital	716
Property, plant and equipment	47,495
Goodwill	8,792
Debt assumed	(8,870)
Site restoration liability	(580)
Future income taxes	(13,266)
Total net assets acquired	34,499
Financed by	
Bank debt	34,374
Acquisition costs	125
Total consideration	34,499

Effective September 26, 2003, Energy acquired all of the issued and outstanding shares of CanScot Resources Ltd. ("CanScot"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Cash	156
Other working capital	22
Property, plant and equipment	32,980
Goodwill	16,884
Debt assumed	(6,150)
Site restoration liability	(388)
Future income taxes	(7,399)
Total net assets acquired	36,105
Financed by	
Bank debt	19,689
Trust units issued (1,342,004 Trust units)	15,433
Acquisition costs	983
Total consideration	36,105

Effective May 30, 2002, Energy acquired all of the issued and outstanding shares of two private corporations, Kinwest Energy Inc. ("Kinwest") and Kinwest's joint venture partner (collectively the "Kinwest Acquisition"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired	
Working capital	1,641
Property, plant and equipment	63,483
Goodwill	11,476
Debt assumed	(10,146)
Site restoration liability	(673)
Future income taxes	(15,410)
Total net assets acquired	50,371
Financed by	
Cash	13,042
Trust units issued (3,385,510 Trust units)	36,056
Acquisition cost – due to related party	838
Acquisition costs	435
Total consideration	50,371

NOTE 8 LONG-TERM DEBT

($000)	**2003**	2002
Bank loans	**98,000**	88,000

At December 31, 2003, APF had a $150.0 million revolving term credit facility with a syndicate of Canadian resident financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The debt bears interest based on a sliding scale tied to APF's debt to cash flow ratio, from a minimum of the bank's prime rate plus 0.125% to a maximum of the prime rate plus 1.625% (2002 – prime rate plus 1.5%) or where available, at Banker's Acceptances rates plus a stamping fee of 1.125% to 2.0% (2002 – 1.125% to 2.5%). The debt is secured by a $300.0 million demand debenture containing a first fixed charge on all the petroleum and natural gas assets of APF and an assignment of book debts and material gas contracts. At December 31, 2003, the interest rate was bank prime of 4.5% plus 0.125% (2002 – 4.5% plus 0.25%).

APF has the option to extend the revolving period for an additional 364 days by giving notice to the lenders no earlier than 180 days and no less than 90 days prior to the end of the revolving period. If the revolving period is not extended, the outstanding principal will be converted to a one-year non-revolving term loan commencing on the day immediately following the end of the then current revolving period. During the one-year term period, APF will pay 1/6th of the outstanding principal on the 180th day after the commencement of the one-year term period and 1/12th of the outstanding principal on the 90th day thereafter.

NOTE 9 UNITHOLDERS' INVESTMENT ACCOUNT

	2003		2002	
		Amounts		Amounts
	Units	**($000)**	Units	($000)
Balance – Beginning of year	**22,942,417**	**214,405**	15,583,880	141,069
Issued to acquire Hawk Oil	**3,990,461**	**37,710**	–	–
Issued to acquire CanScot Resources	**1,342,004**	**15,433**	–	–
Issued to acquire Kinwest	**–**	**–**	3,385,510	36,056
Issued for cash	**5,351,645**	**55,670**	3,303,665	32,250
Cost of units issued	**–**	**(3,467)**	–	(1,861)
Distribution reinvestment program	**140,710**	**1,602**	–	–
Issued on conversion of debentures	**107,998**	**1,215**	–	–
Issued under management internalization	**–**	**–**	608,185	6,337
Issued on exercise of options/rights	**199,005**	**1,749**	61,177	554
Balance – End of year	**34,074,240**	**324,317**	22,942,417	214,405

The holders of Units are entitled to vote at any meeting of the Unitholders.

The per unit calculations are based on the weighted average number of units outstanding during the year of 30,970,093 units (2002 – 20,470,210 units). In computing diluted net income per unit, 334,077 units were added to the weighted average number of units outstanding during the year (2002 – 57,569) for the dilutive effect of employee options and rights to acquire Trust units. In addition, 4,336,444 units were added (2002 – nil) for the dilutive effect of the convertible debentures for a total weighted average number of units for 2003 of 35,640,614 (2002 – 20,527,779).

Net income for 2003 has been adjusted by $2,317,000 (2002 – $nil) for the interest accrued on the convertible debenture for purposes of calculating basic earnings per unit.

In 1999, the Trust created a Unitholders' Rights Plan and authorized the issuance of one right in respect of each Unit outstanding. Each right would allow Unitholders in specified circumstances, to acquire, on payment of an exercise price of $50.00, the number of Units having an aggregate market price equal to twice the exercise price of the rights.

Effective with the December 2003 distribution, the Trust initiated a premium distribution reinvestment plan ("DRIP"). The DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95% of the average market price as defined in the plan ("Regular DRIP").

The premium distribution component permits eligible unitholders to elect to receive 102% of the cash the unitholder would otherwise have received on the distribution date ("Premium DRIP"). Participation in the Regular DRIP and Premium DRIP is subject to proration by the Trust. Unitholders who participate in either the Regular DRIP or the Premium DRIP are also eligible to participate in the optional unit purchase plan as defined in the DRIP.

NOTE 10 TRUST UNIT INCENTIVE RIGHTS PLAN

Pursuant to a Trust Unit Incentive Plan dated December 17, 1996 and amended February 1, 1998 (the "Plan"), employees, directors and long-term consultants may be granted options to acquire Units of the Trust. The exercise price for each option was the market price of the Units at the time the option was granted. Options granted prior to February 1, 1998 vested immediately, while options granted on or after February 1, 1998 vest in one-third increments on the first, second and third anniversaries of their grant. The maximum term for options is five years. This Plan was terminated in 2001 and replaced with a new Trust Unit Incentive Rights Plan ("Rights Plan").

Under the Rights Plan, employees, directors and long-term consultants may be granted rights to purchase Units of the Trust. The initial exercise price of rights granted under the Rights Plan may not be less than the current market price of the Trust Units as of the date of the grant and the maximum term of each right is not to exceed ten years. The exercise price is to be adjusted downwards from time to time by the amount, if any, that distributions to Unitholders in any calendar quarter exceed a percentage of APF's net book value of property, plant and equipment, as determined by the Trust.

APF recorded compensation expense and contributed surplus of $1,241,000 for rights issued in 2003, based on the year-end unit price of $12.54.

For rights granted in 2002, APF has elected to disclose proforma results as if the amended accounting standard has been applied retroactively. For the year ended December 31, 2003, APF's net income would have decreased by $950,000 for the estimated compensation cost associated with rights granted under the plan between January 1 and December 31, 2002 as follows:

($000)	**2003**	2002
Net income as reported	**43,048**	11,365
Less: Compensation expense for rights issued in 2002	**(950)**	–
Pro forma net income	**42,098**	11,365
Basic net income per Trust unit		
As reported	**1.32**	0.55
Proforma	**1.28**	0.55
Diluted net income per Trust unit		
As reported	**1.21**	0.55
Proforma	**1.18**	0.55

No compensation expense has been recorded for 2002 as the adjusted exercise price of the rights exceeded APF's market price at December 31, 2002.

Net income in the basic per Trust unit calculation has been reduced by interest on the convertible debentures of $2.3 million for purposes of calculating the basic net income.

NOTE 11 RIGHTS AND OPTIONS OUTSTANDING

A summary of the status of the Plan as of December 31, 2003 and 2002 is as follows:

Trust Unit Options	**Units**	**2003 Weighted average price ($)**	Units	2002 Weighted average price ($)
Outstanding – beginning of year	**244,029**	**9.13**	330,540	9.32
Granted	–	–	–	–
Exercised	**(106,786)**	**8.55**	(58,677)	9.05
Forfeited	**(10,774)**	**9.42**	(27,834)	11.62
Outstanding – end of year	**126,469**	**9.59**	244,029	9.13
Options exercisable – end of year	**60,173**	**9.48**	76,488	8.72

The following table summarizes options information under the Plan outstanding at December 31, 2003:

Range of Exercise prices ($)	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price ($)	Number exercisable December 31, 2003	Weighted average price ($)
7.00 – 7.99	700	1.18	7.15	700	7.15
8.00 – 9.00	6,899	0.15	8.00	6,899	8.00
9.01 – 10.00	118,870	2.17	9.70	52,574	9.70
	126,469	2.10	9.59	60,173	9.48

Rights plan

During the year, the Trust granted 1,538,250 rights (2002 – 441,233) under the Rights Plan to employees and directors to purchase Trust units at prices ranging from $9.67 to $11.54 (2002 – $9.73 to $10.80) per Trust unit.

A summary of the Rights Plan at December 31, 2003 and 2002 is as follows:

	2003 Number of rights	**2003** Weighted average price ($)	2002 Number of rights	2002 Weighted average price ($)
Balance – beginning of year	**429,333**	**9.37**	–	–
Granted	**1,538,250**	**9.78**	441,233	9.86
Exercised	**(92,219)**	**9.05**	(2,500)	9.73
Cancelled	**(51,034)**	**9.67**	(9,400)	9.73
Balance before reduction of exercise price	**1,824,330**	**9.72**	429,333	9.86
Reduction of exercise price	**–**	**0.63**	–	0.49
Balance – end of year	**1,824,330**	**9.09**	429,333	9.37
Rights exercisable – end of year	**47,221**	**8.58**	–	–

The following table summarizes information about the Rights Plan as at December 31, 2003:

Range of Exercise prices ($)	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price ($)	Number exercisable December 31, 2003	Weighted average price ($)
8.00 – 9.00	222,180	8.17	8.40	40,721	8.49
9.01 – 10.00	1,508,623	9.27	9.06	6,500	9.18
10.01 – 11.00	10,858	9.45	10.45	–	–
11.01 – 12.00	82,669	9.50	11.31	–	–
	1,824,330		9.09	47,221	8.58

NOTE 12 CONVERTIBLE DEBENTURES

On July 3, 2003, APF issued $50.0 million of unsecured subordinated convertible debentures ($47.7 million net of issue costs) with a 9.40% coupon rate maturing July 31, 2008. Interest is paid semi-annually on January 31 and July 31. The debentures may be converted into Trust units at the option of the holder at a conversion price of $11.25 per Trust unit prior to July 31, 2008 and may be redeemed by APF under certain circumstances. The debentures and related interest obligations have been classified as equity on the consolidated balance sheet as APF may elect to satisfy interest and principal obligations by the issuance of Trust units. During the year, $1.2 million of convertible debentures were converted into 107,998 Trust units.

NOTE 13 INCOME TAXES

Energy and the LP have approximately $70.0 million of unused tax pools at December 31, 2003 ($60.4 million – December 31, 2002) available to be used to offset future taxable income subject to certain restrictions of the Income Tax Act.

Energy had approximately $22.3 million in non-capital losses at December 31, 2003 ($15.3 million – December 31, 2002) of which approximately $945,000 expire in 2005 and the remainder through 2010.

The Unitholders are responsible for their own income taxes. Distributions will be a combination of taxable income and a return of capital in the year received. Generally, when the Trust has no taxable income prior to the deduction of distributions, distributions will not be taxable but will be a return of capital which reduces the Unitholders' adjusted cost base in those years.

Distributions paid are deducted from taxable income only to the extent needed to reduce taxable income in the Trust to zero. Generally, the distributions deducted for the Trust tax return are taxable income to the Unitholders.

($000)	**2003**	2002
Income before income taxes	**28,715**	4,635
Statutory tax rate	**42.75%**	43.5%
Expected tax provision	**12,276**	2,016
Effect on income tax of		
Net income of the Trust	**(21,002)**	(12,603)
Resource allowance	**(2,250)**	(595)
Non-deductible crown charges	**669**	47
Internalization of management contract	**–**	3,174
Capital tax	**1,163**	827
Rate reduction	**(3,717)**	–
Other	**(1,472)**	–
Provision for future income taxes	**(14,333)**	(7,134)
The future tax recorded on the balance sheet results from		
Capital assets in excess of tax value	**72,725**	46,282
Future tax losses that are likely to be utilized	**(8,503)**	(6,657)
	64,222	39,625

Taxable income of the Trust is comprised of income from royalty, adjusted for crown royalties and resource allowance, less deductions for Canadian oil and natural gas property expense (COGPE), which is claimed at a rate of 10% on a declining balance basis and issue costs which are claimed at 20% per year on a straight-line basis. Any losses that occur in the Trust must be retained in the Trust and may be carried forward and deducted from taxable income for a period of seven years. The COGPE during 2003 resulted from the purchase of royalty interests.

The amount of COGPE and issue costs remaining in the Trust are approximately $122.3 million.

NOTE 14 RELATED PARTY TRANSACTIONS

Internalization of management

On December 18, 2002, Unitholders approved the acquisition of APF Energy Management Inc. (the "Manager"), effective January 1, 2003. Total consideration for the transaction consisted of a cash payment of $3.9 million and the issuance of 608,185 Trust Units to the shareholders of the Manager as detailed below:

($000)	
Net assets acquired	
Cash	419
Working capital	629
Property, plant and equipment	4,512
Future income taxes	(1,917)
Internalization of management contract	7,297
Total net assets acquired	10,940
Total consideration	
Cash	3,923
Trust units issued	6,337
Transaction costs	680
Total purchase price	10,940

Although the transaction did not close until January 3, 2003, all of the major conditions, including unitholder and regulatory approval, had been obtained by December 31, 2002. Accordingly, the transaction was accounted for as if it had closed on December 31, 2002.

The consideration paid through the issue of Trust Units is partially subject to escrow restrictions. In the case of Mr. Martin Hislop, Chief Executive Officer, 100% of the 150,526 Trust Units issued are subject to escrow for 3 years, released as to one third on each anniversary date of the transaction. In the case of Mr. Cloutier, President and Chief Operating Officer, 80% of the 125,590 Trust Units issued are subject to escrow for 4 years, released as to one quarter on each anniversary date of the transaction. The remaining Trust Units issued to non-management shareholders of the Manager were not subject to escrow restrictions. Retention bonuses paid by the Manager to three other officers were used to subscribe for 53,665 Trust Units at a price of $10.482 per Trust Unit at closing. These Trust Units are subject to the same escrow restrictions as those Trust Units issued to the President.

Prior to the acquisition, APF paid fees to the Manager equal to 3.5% of net production revenue, structuring fees of 1.5% on the purchase price of acquisitions and dispositions, as well as the right to the residual 1% royalty. The internalization resulted in the elimination of all such fees under the management agreement.

Management contract

Prior to the internalization of the management contract, the Manager handled the business of APF pursuant to a management agreement. Fees payable to Management for management, advisory and administrative services included a fee equal to 3.5% of Net Production Revenue and structuring fees of 1.5% on both the purchase price of acquisitions and on the net proceeds of dispositions. In 2003, fees paid or payable to Management on Net Production Revenues were $nil (2002 – $1,976,000) and structuring fees were $nil (2002 – $1,022,000). During 2002 structuring fees were accounted for as either part of the purchase price or as a reduction of the proceeds of disposition of oil and natural gas properties.

During the year, Energy reimbursed Management $nil (2002 – $2,294,000) for general and administrative expenses. During 2002, Energy also acquired certain non-oil and gas business assets from Management for $850,000.

During 2002, Management, through its ownership of 100% of the shares of APF, was entitled to receive 1% of the royalty income derived from the Properties. The 1% minority interest is included as an expense in the consolidated statement of operations totalling $403,000 for 2002.

NOTE 15 FINANCIAL INSTRUMENTS

APF is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Derivative instruments are used by APF to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity.

The fair values of financial instruments that are included in the balance sheet, including long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments and the floating prime rate applied to long-term borrowings.

A substantial portion of APF's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

APF has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. APF sells forward a portion of its future production through commodity swap agreements with counterparties. The following contracts were outstanding as at December 31, 2003. The estimated market value at December 31, 2003, had the contracts been settled at that time, would have resulted in a reduction of revenues otherwise to be received of $400,000.

Term	Commodity	Type of contract	Average daily quantity	Average contract price	Price index
Jan. to Mar. 2004	Crude oil	Fixed price	3,167 bbls	$U.S. 29.63	WTI
Jan. to Mar. 2004	Natural gas	Fixed price	10,000 GJ	$Cdn. 7.19	AECO
Jan. to Mar. 2004	Natural gas	Fixed price	2,000 mmbtu	$U.S. 7.00	NYMEX
Apr. to Jun. 2004	Crude oil	Fixed price	1,833 bbls	$U.S. 30.05	WTI
Jul. to Sept. 2004	Crude oil	Fixed price	1,167 bbls	$U.S. 28.86	WTI

At December 31, 2003, APF had fixed the interest rate on a portion of its debt as follows:

Term	Amount ($000)	Interest rate
January 2004 to February 2005	$20,000	3.67% plus stamping fee
January 2004 to May 2005	$20,000	3.75% plus stamping fee
January 2004 to November 2005	$20,000	3.58% plus stamping fee

The estimated market value of these interest rate contracts at December 31, 2003, had they been settled at that time, would be a cost of $900,000.

At December 31, 2003, APF had entered into the following foreign currency forward contract:

Term	Amount ($000)	Exchange rate ($Cdn./$U.S.)
January 2004 to December 2004	$U.S. 10,000	1.333

The estimated market value of these foreign currency forward contracts at December 31, 2003, had they been settled at that time, would be $nil.

NOTE 16 SUPPLEMENTAL INFORMATION FOR THE STATEMENTS OF CASH FLOWS

($000)	**2003**	2002
Cash payments related to certain items		
Interest	**4,070**	2,843
Interest on debentures	**30**	–
Distributions to minority interests	**–**	415
Distributions to Unitholders	**66,315**	36,539
Capital taxes	**3,389**	2,165

NOTE 17 CONTINGENCIES AND COMMITMENTS

APF is involved in certain legal actions that occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

APF has lease commitments relating to office buildings. The estimated annual operating lease rental payments for the building for the next five years are as follows:

($000)	
2004	773
2005	756
2006	710
2007	706
2008	359

NOTE 18 SUBSEQUENT EVENTS

Underwriting Agreement and prospectus filing

APF and the Underwriters entered into an Underwriting Agreement pursuant to which the Underwriters agreed to offer and the Trust agreed to issue and sell up to 4,765,000 Trust Units at a price of $11.60 per Trust Unit. Closing of the offering and the issue of 4,765,000 Trust Units took place on February 4, 2004. The estimated net proceeds from the offering, after deducting expenses of the issue and after Underwriters' commissions will be in the amount of $52.5 million and will be initially used to repay debt.

Five Year Review (unaudited)

	2003	2002	2001	2000	1999
FINANCIAL ($000 except per unit amounts)					
Revenue before royalties	**165,457**	94,021	69,924	44,974	24,707
Per unit basic	**$5.34**	$4.59	$5.56	$6.53	$4.19
Cash flow (1)	**83,326**	43,788	33,995	23,706	3,334
Per unit basic	**$2.69**	$2.14	$2.70	$3.44	$0.57
Net income (4)	**43,048**	11,365	18,144	14,075	(4,689)
Per unit basic	**$1.32**	$0.55	$1.44	$2.04	$(0.80)
Cash distributions	**68,713**	37,766	37,311	13,899	9,188
Per unit basic	**$2.195**	$1.810	$2.980	$1.995	$1.560
Bank debt	**98,000**	88,000	59,250	25,736	33,171
UNITS OUTSTANDING (000)					
Year-end	**34,074**	22,942	15,584	7,139	5,890
Average	**30,970**	20,470	12,578	6,888	5,890
MARKET					
High	**$12.67**	$11.19	$13.40	$10.40	$9.70
Low	**$9.30**	$9.00	$8.75	$7.00	$7.25
Close	**$12.54**	$9.79	$9.85	$9.75	$8.10
Volume (000)	**41,359**	17,314	11,645	2,520	2,394
Value ($000)	**463,074**	175,935	123,767	21,711	20,196
OPERATIONS					
Production					
Oil (bbl/d)	**6,472**	5,307	3,167	1,152	1,104
Natural gas (mcf/d)	**33,799**	18,488	15,391	13,449	13,656
NGL's (bbls/d)	**358**	144	100	254	274
Total (boe/d)	**12,463**	8,532	5,832	3,648	3,654
Annual (mboe)	**4,549**	3,114	2,129	1,335	1,334
Commodity Sales Prices (net of hedging)					
Oil ($/bbl)	**34.46**	33.66	33.64	41.40	25.00
Natural gas ($/mcf)	**6.32**	3.83	4.94	4.72	2.36
NGL's ($/bbl)	**31.82**	25.15	30.97	35.96	18.19
Average ($/boe)	**35.95**	29.65	31.94	32.98	17.74
Reserves - proved plus probable (2)					
Crude oil & NGL's (mbbl)	**23,789**	20,608	13,545	5,648	6,216
Natural gas (mmcf)	**99,197**	68,290	50,984	46,364	41,366
Total (mboe) (3)	**40,322**	31,989	22,042	13,375	13,110
ECONOMICS ($/boe)					
Average oil & gas sales price (net of hedging)	**35.95**	29.65	31.94	32.98	17.74
Other income	**0.42**	0.54	0.89	0.69	0.77
Net selling price	**36.37**	30.19	32.85	33.68	18.50
Royalties	**7.14**	6.01	6.28	6.39	2.92
Operating costs	**7.12**	6.35	6.15	6.01	5.47
Netbacks	**22.11**	17.83	20.42	21.28	10.11
General & administrative costs	**2.20**	1.49	1.58	1.38	0.85
Management fees	**-**	0.63	0.71	0.74	0.35
Interest	**0.92**	0.91	1.43	1.41	1.47
Taxes	**0.60**	0.61	0.55	0.12	0.07
Site restoration	**0.73**	0.67	0.61	0.68	0.48
Cash flow from operations (1)	**18.32**	14.14	15.97	17.59	7.20

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and accrued interest on convertible debentures.

(2) Reserve numbers are based on established (proved plus 50 percent probable) Company Interest Reserves prior to royalties for 2002 and for 2003 are based on total proved plus probable Company Interest Reserves prior to royalties as defined in National Instrument 51-101 ("NI 51-101").

(3) Boe's may be misleading, particularly if used in isolation. In accordance with NI 51-101, 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.

(4) Net income in the basic per Trust unit calculation has been reduced by interest accrued on the convertible debentures.

Management's Discussion and Analysis

The following discussion should be read in conjunction with the audited consolidated financial statements included in the annual report. The financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars. Additional information relating to APF, including disclosures required under National Instrument 51-101, can be found in APF's Annual Information Form ("AIF") on SEDAR at www.sedar.com or on APF's website at www.apfenergy.com.

PRODUCTION

During the fourth quarter, production increased by 38% over the same period in 2002. Production volumes for the year were 46% higher in 2003, due primarily to the acquisitions of Hawk Oil Inc. ("Hawk"), Nycan Energy Corp. ("Nycan") and CanScot Resources Ltd. ("CanScot"). Natural production declines were partially offset throughout the year by production increases from successful development drilling programs at Queensdale, Macoun and Tatagwa in Southeast Saskatchewan and at Countess in Southeast Alberta. A $40 million capital expenditure budget has been set forth in 2004 and is expected to maintain production levels at the 2003 exit rate of approximately 13,000 boe/d.

	Three Months Ended December 31			Year Ended December 31		
	2003	2002	% Change	**2003**	2002	% Change
Crude oil (bbl/d)	**6,499**	6,001	8	**6,472**	5,307	22
Natural gas (mcf/d)	**36,929**	19,776	87	**33,799**	18,488	83
NGL (bbl/d)	**474**	187	153	**358**	144	149
Total (boe/d)[1]	**13,128**	9,484	38	**12,463**	8,532	46
Production split						
Oil & NGLs	**53%**	65%		**55%**	64%	
Natural gas	**47%**	35%		**45%**	36%	

[1] Boe's may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), 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.

MARKETING

In 2003, APF's production mix was 55% crude oil and NGLs and 45% natural gas. Crude oil was sold under 30-day evergreen contracts while approximately 25% of natural gas production was sold to aggregators pursuant to long-term contracts, with the remaining 75% sold on the spot market.

PRICES

During the fourth quarter of 2003, price realizations declined a modest 3% for the same quarter in 2002, due largely to a 16% decrease in the value of the U.S. dollar against the Canadian dollar. Oil pricing was most affected by the change in currency exchange rates, with price realizations decreasing by 12% while the benchmark West Texas Intermediate ("WTI") pricing increased 11% over the fourth quarter of 2002. Natural gas pricing during the quarter increased by 14% over the same period in 2002.

WTI oil prices averaged $U.S. 31.06 per bbl in 2003, 19% higher than the 2002 average of $U.S. 26.10. Crude oil prices in Canada are based on the WTI reference price, adjusted for transportation, differentials and foreign exchange. The price received by APF is based upon the refiners' posted price, less transportation and adjustments for APF's product quality relative to the posted price and adjusted for hedging. APF's oil price after hedging averaged $34.46 per bbl in 2003, compared with $33.66 per bbl in 2002, an increase of 2%.

Canadian oil prices were negatively impacted by an average 11% decrease in the value of the U.S. dollar versus the Canadian dollar during 2003. The NYMEX futures contracts for the remainder of 2004 suggest crude oil prices will exceed 2003 levels during the year.

APF's realized natural gas price after hedging for the year averaged $6.32 per mcf, 65% higher than the average realized price of $3.83 per mcf in 2002. This is consistent with the increase in the benchmark AECO price in Alberta, which increased by an average of 63% from 2002 levels. APF expects gas prices during 2004 to remain consistent with or exceed 2003 levels as supply concerns dominate the market.

	Three Months Ended December 31			Year Ended December 31		
	2003	2002	% Change	**2003**	2002	% Change
Prices - After Hedging						
Crude oil ($Cdn./bbl)	**$ 31.66**	$ 35.80	(12)	**$ 34.46**	$ 33.66	2
Natural gas ($Cdn./mcf)	**5.41**	4.74	14	**6.32**	3.83	65
NGL ($Cdn./bbl)	**31.37**	30.63	2	**31.82**	25.15	27
Total ($Cdn./boe)	**$ 32.03**	$ 33.14	(3)	**$ 35.95**	$ 29.65	21
Reference Pricing						
WTI ($U.S./bbl)	**$ 31.18**	$ 28.14	11	**$ 31.06**	$ 26.10	19
AECO gas ($Cdn./mcf)	**$ 5.59**	$ 5.25	6	**$ 6.67**	$ 4.08	63
Foreign exchange ($U.S./$Cdn.)	**$ 1.3157**	$ 1.5695	(16)	**$ 1.4010**	$ 1.5703	(11)

HEDGING

Commodity prices are susceptible to market fluctuations. APF actively manages commodity price risk by entering into hedging contracts to protect revenues from fluctuations in commodity prices. Hedging is intended to provide stability to cash distribution levels by fixing the price of commodities on a portion of the production portfolio. One of the key assumptions in the preparation of APF's annual budget and estimate of annual distributions is commodity price. APF's mandate is to ensure that a portion of the year's distributions, based on certain commodity price assumptions, are protected. APF looks for opportunities to sell forward a portion of its production at levels at, or better than, the commodity prices used in the budget process. While this guideline necessarily implies that commodity prices may rise, it must be acknowledged that commodity prices may fall. In this regard, in situations where commodity prices are below those used in the annual budget, management's expertise is relied upon to ensure that potential opportunities to mitigate the impact of lower commodity prices are executed. Hedging activities during 2003 reduced revenues by $3.56 million, reducing the realized oil price by $1.61 per bbl and increasing the natural gas price by $0.02 per mcf. At the time of printing APF had the following hedges in place:

Current Hedging Position

Period	Type of Commodity	Average Contract	Average Daily Quantity	Hedged Price
March 2004	Crude oil	Swap	3,000 bbls	$U.S. 30.76/bbl
March 2004	Natural gas	Swap	10,000 GJ	$Cdn. 7.19/GJ
March 2004	Natural gas	Physical	2,000 mmbtu	$U.S. 7.00/mmbtu
April to June 2004	Crude oil	Swap	2,500 bbls	$U.S. 30.78/bbl
April to June 2004	Natural gas	Swap	10,333 GJ	$Cdn. 5.76/GJ
April to June 2004	Natural gas	Swap	1,000 mmbtu	$U.S. 5.19/mmbtu
July to September 2004	Crude oil	Swap	2,167 bbls	$U.S. 29.58/bbl
July to September 2004	Natural gas	Swap	10,000 GJ	$Cdn. 5.75/GJ
July to September 2004	Natural gas	Swap	1,000 mmbtu	$U.S. 5.19/mmbtu
October to December 2004	Crude oil	Swap	1,833 bbls	$U.S. 30.45/bbl
October to December 2004	Natural gas	Swap	3,333 GJ	$Cdn. 5.75/GJ
October to December 2004	Natural gas	Swap	333 mmbtu	$U.S. 5.19/mmbtu
January 2005	Crude oil	Swap	1,000 bbls	$U.S. 31.74/bbl

In addition to commodity hedging, APF has also entered into foreign currency hedge contracts in order to mitigate currency risk. The Trust has hedged $U.S. 20 million of revenue at a rate of $Cdn. 1.3317 or $U.S. 0.7509 for calendar 2004.

At December 31, 2003, APF had fixed the interest rate on a portion of its debt as follows:

Term	Amount (000)	Interest Rate
January 2004 to February 2005	$ 20,000	3.67% plus stamping fee
January 2004 to May 2005	$ 20,000	3.75% plus stamping fee
January 2004 to November 2005	$ 20,000	3.58% plus stamping fee

REVENUES

Revenues for the fourth quarter of 2003, net of hedging, increased to $39 million from $29 million during the fourth quarter of 2002. Increased revenues from natural gas contributed to 46% of total revenue in the fourth quarter of 2003, an increase of $9.2 million over the same period in the previous year.

Annual revenues, net of hedging transactions increased 76% to $165 million in 2003, due to a combination of higher production volumes and higher commodity prices.

Oil and Gas (000 except per boe amounts)	Three Months Ended December 31 2003	% of Total	2002	% of Total	Year Ended December 31 2003	% of Total	2002	% of Total
Crude oil sales	**$ 19,536**	**50**	$ 20,948	71	**$ 85,193**	**51**	$ 69,390	74
Natural gas sales	**17,830**	**46**	8,624	29	**77,747**	**47**	25,534	27
NGL sales	**1,367**	**3**	597	2	**4,157**	**3**	1,320	1
Hedging	**(44)**	**--**	(1,180)	(4)	**(3,565)**	**(2)**	(3,899)	(4)
Other	**421**	**1**	461	2	**1,925**	**1**	1,676	2
Total revenue	**39,110**	**100**	29,380	100	**165,457**	**100**	94,021	100
Per boe	**$ 32.38**		$ 33.67		**$ 36.37**		$ 30.39	

ROYALTIES

For the fourth quarter, royalties as a percentage of revenue were 5% higher in 2003, as a result of higher commodity pricing. Royalties per barrel of oil equivalent produced were 19% higher in 2003, consistent with the increase in commodity prices during the year. Royalties as a percentage of revenues were essentially unchanged.

(000 except per boe amounts)	Three Months Ended December 31 2003	2002	% Change	Year Ended December 31 2003	2002	% Change
Crown royalties	**$ 4,838**	$ 2,862	69	**$ 19,364**	$ 10,905	78
Freehold royalties	**2,120**	2,310	(8)	**10,193**	6,323	61
Overriding royalties	**609**	265	130	**2,916**	1,479	97
Total royalties	**$ 7,567**	$ 5,437	39	**$ 32,473**	$ 18,707	74
% of revenue after hedging	**19.3%**	18.5%	5	**19.6%**	19.9%	(1)
Per boe	**$ 6.26**	$ 6.23	--	**$ 7.14**	$ 6.01	19

OPERATING COSTS

Fourth quarter operating costs increased by 16% over the same period in 2002, while annual costs increased by 12% in 2003 to average $7.12 per boe. Increases were primarily due to initial field optimization costs on newly acquired properties and higher energy costs. Continued high energy costs and general higher field costs associated with APF's current property portfolio are expected to negate any operating efficiencies initiated to reduce operating costs in 2004.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Operating costs	**$ 9,619**	$ 5,970	61	**$ 32,370**	$ 19,748	64
Per boe	**$ 7.97**	$ 6.84	16	**$ 7.12**	$ 6.35	12

NETBACKS

Netbacks decreased from $20.60 per boe in the fourth quarter of 2002 to $18.15 per boe during the fourth quarter of 2003, resulting from lower revenues which were negatively impacted by currency exchange rates and a 16% increase in operating costs. Higher commodity prices during 2003 offset increased royalty expenses and operating costs during 2003, resulting in annual operating netbacks of $22.11/boe, a 24% increase from 2002.

	Three Months Ended December 31			Year Ended December 31		
($ per boe)	**2003**	2002	% Change	**2003**	2002	% Change
Net revenue (after hedging)	**$ 32.38**	$ 33.67	(4)	**$ 36.37**	$ 30.19	20
Royalties	**(6.26)**	(6.23)	–	**(7.14)**	(6.01)	19
Operating costs	**(7.97)**	(6.84)	16	**(7.12)**	(6.35)	12
Netback	**$ 18.15**	$ 20.60	(12)	**$ 22.11**	$ 17.83	24

GENERAL AND ADMINISTRATIVE

General and administrative costs increased in absolute terms for both the quarterly and annual periods of 2003, by 157% and 116% respectively, compared with 2002. The increase is due primarily to costs associated with the increase in staffing levels from recent corporate and property acquisitions and the cost of APF's short-term incentive plan ("STIP"), which was introduced for 2003 following the termination of the management contract.

The STIP was created to encourage and reward outstanding employee performance and to ensure that the interests of both the unitholders and employees were aligned. The STIP enables all eligible employees to participate in a bonus pool, provided APF generates at least a 10% total annual return. Total annual return is calculated as distributions paid during the year plus or minus the change in unit price compared with the previous year-end. When the 10% total return threshold is met, a portion of net operating income ("NOI") is allocated to the bonus pool and shared by all eligible employees. The total return on APF units for the year ended December 31, 2003 was 50%. Based on this total return, the bonus pool under the STIP for the year was $3.35 million (2002 - $nil). Senior employees, including officers, may also be eligible to receive performance bonuses based on criteria applicable to each individual's responsibilities. Excluding the STIP, general and administrative costs per boe for the year ended December 31, 2003 were $1.47.

APF's success at finding and developing oil and gas reserves is due to its ability to recruit highly competent individuals with strong technical skill sets. Accordingly, APF's compensation structure is designed to provide employees with a competitive base package and the potential to enhance the base, provided unitholders experience strong returns.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
General and administrative	**$ 3,980**	$ 1,547	157	**$ 10,023**	$ 4,635	116
Per boe	**$ 3.30**	$ 1.77	86	**$ 2.20**	$ 1.49	48

MANAGEMENT FEE

Prior to the internalization of the management contract, the Manager received a management fee equal to 3.5% of net production revenue. During 2002, management fees amounted to $1.98 million ($0.63 per boe) compared with $0.65 million ($0.75 per boe) for the fourth quarter 2002. Commencing January 1, 2003, no management fees were payable.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Management fee	**$ –**	$ 654	(100)	**$ –**	$ 1,976	(100)
Per boe	**$ –**	$ 0.75	(100)	**$ –**	$ 0.63	(100)

INTEREST

Interest expense increased 27% and 47% for the fourth quarter and year ended 2003 respectively. The increases were due to higher average debt levels arising from the various corporate and property acquisitions completed during 2003. At December 31, 2003, APF had fixed the interest rate on $60 million of debt (2002 - $30 million) at an average rate of 3.67% (2002 - 3.76%) plus applicable stamping fee, maturing in 2005.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Interest	**$ 1,087**	$ 854	27	**$ 4,171**	$ 2,834	47
Per boe	**$ 0.90**	$ 0.98	(8)	**$ 0.92**	$ 0.91	1

DEPLETION, DEPRECIATION AND AMORTIZATION

Depletion, depreciation and amortization ("DD&A") increased by 68% per boe in the fourth quarter of 2003 from the same period in 2002 and 14% for the year to $13.90 and $11.08 per boe respectively. The increases reflect the current year's acquisitions being higher than the historical average cost per boe.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Depletion and amortization	**$ 16,791**	$ 7,226	132	**$ 50,417**	$ 30,200	67
Per boe	**$ 13.90**	$ 8.28	68	**$ 11.08**	$ 9.70	14

SITE RESTORATION

Site restoration increased by 4% per boe during the fourth quarter from the same period in 2002 and by 9% to $0.73 per boe for the year, reflecting the future incremental site reclamation costs associated with acquisitions completed during 2003.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	**2003**	2002	% Change	**2003**	2002	% Change
Site restoration	**$ 827**	$ 576	44	**$ 3,327**	$ 2,087	59
Per boe	**$ 0.69**	$ 0.66	4	**$ 0.73**	$ 0.67	9

COMPENSATION EXPENSE

During 2003, as part of APF's long-term incentive plan, 1,538,250 Trust unit incentive rights (2002 - 441,233) were issued to employees and directors, at prices ranging from $9.67 to $11.54 per Trust unit (2002 - $9.73 to $10.80). The exercise price of the rights is adjusted downward over time by the amount, if any, that quarterly distributions exceed 2.5 % of the net book value of property, plant and

Management's Discussion and Analysis

equipment. The rights have a 10-year term and vest in one-third increments on the first, second and third anniversaries of their grant. Rights to purchase 1,824,330 Trust units at an average adjusted exercise price of $9.09 were outstanding at December 31, 2003. These rights have an average remaining contractual life of 9.3 years and expire at various dates to September, 2013. There were 47,221 rights exercisable at December 31, 2003 (2002 – nil).

APF has prospectively adopted the CICA Handbook Section 3870 – "Stock Based Compensation". Under the transitional adoption rules, companies that prospectively adopt at December 31, 2003 are only required to recognize compensation expense for those options granted during 2003, with proforma disclosure of options granted during 2002.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	2003	2002	% Change	2003	2002	% Change
Compensation expense	$ 582	$ –	100	$ 1,241	$ –	100
Per boe	$ 0.48	$ –	100	$ 0.27	$ –	100

APF adopted the new Handbook section during the fourth quarter of 2003. The first three quarters of 2003 have been restated as a result of adopting the standard. APF grants options annually. Compensation expense for the first quarter relates only to options granted in 2002.

	2003				2002			
(000)	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Net income (loss) as reported	$ 13,616	$ 21,137	$ 11,405	$ (2,528)	$ 2,414	$ 4,429	$ 5,463	$ (942)
Compensation expense	(8)	(217)	(434)	(582)	–	–	–	–
Restated net income (loss)	$ 13,608	$ 20,920	$ 10,971	$ (3,110)	$ 2,414	$ 4,429	$ 5,463	$ (942)

TAXES

Saskatchewan capital tax and federal large corporation tax increased by 44% during the quarter and 43% for the year ended December 31, 2003 and reflects the higher proportion of business in the Province of Saskatchewan and higher paid up capital.

Future income taxes are recorded on corporate acquisitions to the extent the book value of assets acquired, excluding goodwill, exceeds the tax basis. This future income tax liability increases the book cost of the assets acquired. It is anticipated that the future income tax liability will not be paid by APF Energy, but will instead be passed on to unitholders along with the income. Accordingly, this income tax liability will reduce each year and will be recognized as an income tax recovery at that time, to the extent that no income taxes were paid by APF Energy. In 2003, APF recorded a recovery of income taxes of $14.3 million compared with $7.1 million in 2002, leaving a balance of $64.2 million in future income taxes payable at December 31, 2003.

During 2003, the Canadian government enacted Federal income tax changes for the oil and gas resource sector as outlined in its 2003 Budget. The federal income tax changes effectively reduced the statutory tax rates for current and future periods, resulting in a significant increase in the future tax recovery (a non-cash item) compared with the first quarter and prior years. Specifically, the current 100% deductibility of the resource allowance will be completely phased out by the year 2007. During the same time frame, Crown charges will become 100% deductible and resource tax rates will decline from the current 27% to 21%. APF realized a future income tax recovery of approximately $9 million during the second quarter relating to this income tax change.

	Three Months Ended December 31			Year Ended December 31		
(000 except per boe amounts)	2003	2002	% Change	2003	2002	% Change
Capital and other taxes	$ 624	$ 433	44	$ 2,721	$ 1,901	43
Per boe	$ 0.52	$ 0.50	4	$ 0.60	$ 0.57	5
Recovery of future income taxes	$ 482	$ 198	143	$ (14,333)	$ (7,134)	101

INTERNALIZATION OF MANAGEMENT CONTRACT

On December 18, 2002, the unitholders approved the internalization of management and effective December 31, 2002, the Trust acquired all of the shares of APF Energy Management Inc. The acquisition resulted in the elimination of all management fees including the 3.5% fee on net operating income, a structuring fee of 1.5% on acquisitions and dispositions and the 1% residual royalty.

The total purchase price of the shares, including transaction costs, was $10.9 million, of which $4.6 million was paid in cash and $6.3 million was paid with Trust units, a portion of which are subject to certain escrow provisions. Of the total, $7.3 million was recorded as an expense in 2002.

NET EARNINGS

Earnings were up 279% to $43.0 million or $1.32 per Trust unit ($1.21 diluted) in 2003 compared with $11.4 million or $0.55 per Trust unit ($0.55 diluted) in 2002. The increase is attributable to both increases in production and commodity prices received throughout 2003.

Earnings per unit in the fourth quarter of 2003 declined as a result of increased general and administrative as well as DD&A expenses. Net earnings for the fourth quarter of 2002 decreased primarily as a result of the one-time, $7.3 million internalization expense.

Selected Annual Information (000 except per unit amounts)	2003	2002	2001
Total revenue	$ 165,457	$ 94,021	$ 69,924
Net earnings	$ 43,048	$ 11,365	$ 18,144
Per unit - basic	$ 1.32	$ 0.55	$ 1.44
Per unit - diluted	$ 1.21	$ 0.55	$ 1.44
Total assets	$ 484,287	$ 297,627	$ 198,175
Total long-term debt	$ 98,000	$ 88,000	$ 59,250
Distributions	$ 68,713	$ 37,766	$ 37,311
Per unit - basic	$ 2.195	$ 1.810	$ 2.980

APF's growth over the past year has been driven by the acquisitions of Hawk, Nycan and CanScot and an active development and optimization program. Growth in 2002 was positively impacted by drilling and the corporate acquisition of Kinwest Resources Inc. APF's natural gas production has increased as a percentage of total production in the past year with APF benefiting from strong gas prices, which are expected to remain strong in 2004.

SUMMARY OF QUARTERLY RESULTS

(000 except per unit amounts)	2003 Q1	2003 Q2	2003 Q3	2003 Q4	2002 Q1	2002 Q2	2002 Q3	2002 Q4
Revenue	$ 44,502	$ 41,876	$ 39,970	$ 39,110	$ 16,941	$ 21,495	$ 26,204	$ 29,380
Net earnings	$ 13,616	$ 21,137	$ 11,405	$ (3,110)	$ 2,414	$ 4,429	$ 5,463	$ (942)
Per unit - basic	$ 0.54	$ 0.66	$ 0.32	$ (0.09)	$ 0.14	$ 0.22	$ 0.25	$ (0.04)
Per unit - diluted	$ 0.54	$ 0.65	$ 0.31	$ (0.09)	$ 0.14	$ 0.22	$ 0.25	$ (0.04)

Management's Discussion and Analysis

CAPITAL EXPENDITURES, ACQUISITIONS AND DISPOSITIONS

Net capital expenditures, including net property and corporate acquisitions, were $191 million in 2003 (2002 - $101 million). Of the total, $33.6 million was incurred for drilling and completions, geological, geophysical and production facilities expenditures, as APF continues to develop its asset base, with the remaining $158.1 million attributable to net property and corporate acquisitions. The 2003 corporate acquisitions of Hawk, Nycan and CanScot totalled $137.6 million, accounting for 72% of net capital expenditures during the year.

	Year Ended December 31		
(000)	**2003**	2002	% Change
Corporate acquisitions	**$ 137,622**	$ 62,143	121
Property acquisitions	**26,928**	27,958	(4)
Land acquisitions	**2,310**	616	275
Seismic	**1,070**	497	115
Drilling and completions	**24,287**	15,890	53
Production facilities	**7,749**	3,684	110
Other	**494**	908	(46)
Subtotal	**200,460**	111,696	79
Dispositions	**(9,284)**	(10,569)	(12)
Net capital expenditures	**$ 191,176**	$ 101,127	89

CASH DISTRIBUTIONS

Cash distributions for 2003 were $68.7 million, or $2.195 per Trust unit, compared with $37.8 million or $1.81 per Trust unit in 2002. During 2003, APF funded $9.3 million of capital expenditures from cash flow (2002 – $5.1 million), resulting in a payout ratio of 87% (2002 – 88%). For 2004, APF intends to maintain its historical policy of retaining a portion of available cash flow to fund capital expenditures and development initiatives, with a target range of 15% to 20%.

DISTRIBUTION REINVESTMENT PLAN

On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003. The DRIP allows eligible unitholders to direct that their monthly cash distributions be reinvested in additional Trust units at 95% of the average market price (as defined in the DRIP) on the applicable distribution date.

The DRIP includes a feature which allows eligible unitholders to elect, under the premium distribution component, to have these additional Trust units delivered to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such unitholders would have otherwise been entitled to receive on the applicable distribution date.

The DRIP also allows those unitholders who participate in either the distribution reinvestment component or the premium distribution component to purchase additional Trust units directly from APF for cash at a purchase price equal to the average market price (with no discount) in minimum amounts of $1,000 per remittance and up to $100,000 aggregate amount of remittances by a unitholder in any calendar month, all subject to an overall annual limit of 2% of the outstanding Trust units.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2003, APF had a revolving term credit facility in the amount of $150 million, with a borrowing base of $150 million, of which $98 million was drawn. The facility may be drawn down or repaid at any time, and there are no scheduled repayment terms.

On July 3, 2003, APF closed a $50.0 million 9.40% convertible unsecured subordinated debenture offering. At December 31, 2003, the balance of convertible debentures net of conversions was $48.8 million including accumulated interest of $2.3 million.

During the fourth quarter of 2003, $11.9 million (2002 - $7.6 million) was spent on development and optimization, $3.6 million (2002 - $23.5 million) on producing property acquisitions and $6.9 million (2002 - $0.8 million) was received for property dispositions.

At December 31, 2003, APF had a working capital deficit of approximately $10.2 million, compared with a working capital surplus of $0.4 million at December 31, 2002. The primary reasons for the working capital deficiency at December 31, 2003 are the significant increase in development drilling activity at December 31, 2003, resulting in higher capital expenditure accruals, along with the accrual for the STIP and provision for the semi-annual payment of debenture interest due January 31, 2004. Subsequent to year-end, APF raised $55.2 million through an equity issue and the proceeds were used to fund the working capital deficit and pay down long-term debt.

APF has budgeted the following amount for its capital program in 2004. Approximately 85% of the $40 million has been allocated for drilling and optimization initiatives.

2004 Estimated Capital Spending

Area	$ (millions)	% of Total
Central Alberta	$ 9.2	23
East Alberta/Heavy Oil	1.4	4
Southern Alberta	8.0	20
Southeast Saskatchewan	14.1	35
Coalbed Methane	7.3	18
Total	$ 40.0	100

The capital program will be funded through a combination of cash flow, distribution re-investment proceeds and debt, with a record 167 gross wells to be drilled for both conventional and coalbed methane ("CBM") opportunities.

CBM development is expected to result in the drilling of 63 gross wells in 2004. Canadian operations will focus on test wells at Doris and Timeu and completion of a 10-well pilot project in the Mannville coals at Corbett Creek. In the United States, development will continue on several projects in the Powder River Basin as APF looks to expand current operations.

UNITHOLDERS' EQUITY

At December 31, 2003, APF had 34.1 million Trust units outstanding (2002 – 22.9 million) and a market capitalization of approximately $427.1 million (2002 – $224.6 million).

In February, 2003, APF issued 4.0 million Trust units at $9.45 per Trust unit for the acquisition of Hawk Oil.

In April, 2003, APF issued 5.4 million Trust units at $10.40 per Trust unit for gross proceeds of $55.7 million. Proceeds from this issue were used to finance the purchase of Nycan and to reduce bank debt.

In June, 2003, APF issued 50,000, 9.4% convertible unsecured subordinated debentures for the acquisition of a 17% interest in Swan Hills Unit No. 1. APF signed a purchase and sale agreement with a third party, for 17% of the Unit for $91.8 million, that was subject to certain rights of first refusal ("ROFR") by another party. The party exercised the ROFR, which resulted in APF receiving 2.55% of the Unit for approximately $15.9 million. The remainder of the debenture issue was used to reduce bank debt and ultimately to partially fund the acquisition of CanScot in September.

In September, 2003, APF issued 1.3 million Trust units at $11.50 per Trust unit for the acquisition of CanScot.

In December, 2003, APF issued 140,710 Trust units pursuant to the new Premium Distribution Reinvestment Plan for proceeds of $1.60 million (2002 - $nil).

During 2003, 199,005 Trust units (2002 - 61,727) were issued pursuant to the Trust unit incentive plan for total proceeds of $1.8 million (2002 - $0.5 million). An additional 107,998 units were issued during the year upon conversion of debentures.

On February 4, 2004, APF closed the issue of 4.8 million Trust units at a price of $11.60 each for gross proceeds of $55.3 million. The proceeds of this offering were used to fund working capital and pay down debt.

Commitments and Contingencies

APF is involved in certain legal actions that occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

APF has compiled a capital budget that has been approved by the Board. The budget forecast is a best estimate of the projects that APF intends to undertake during the year, but does not constitute a legal or contractual obligation to do so. For properties that APF does not operate, a commitment to complete a project at a given future date may be required from the operator. As of the first quarter of 2004, APF has not committed any material funds for these projects.

(000)	2004	2005	2006	2007	2008
Lease commitments	$ 773	$ 756	$ 710	$ 706	$ 359

BUSINESS RISKS

APF is faced with a number of business risks that are inherent in the oil and gas industry and which can have an impact on distributions to unitholders. To mitigate these risks, APF follows appropriate policies and procedures in its ongoing operations and in its long-term strategic planning.

Financial and market risks associated with commodity prices and foreign currency exchange rates are mitigated through APF actively managing the sale of its own production to maximize price and through the use of a hedging program to hedge commodity prices and foreign currency rates with creditworthy counterparties. Hedging is employed as a risk management tool and not for speculation. APF entered into three interest rate swaps during 2003, which expire at various dates in 2005.

There are inherent operational risks associated with oil and natural gas production, relating to the ability to produce, process and transport oil and natural gas, the ability to replace production and maintain reserves and environmental and safety risks associated with well and production facilities. To mitigate these risks, APF employs a strategy of operating a significant portion of its production, thereby providing greater control over operations; APF employees and contractors adhere to APF's safety program and keep current on changes to operating practices, and APF maintains insurance coverage to minimize the impact of operational losses.

APF's ability to grow is dependent upon its ability to raise debt and equity capital in the Canadian capital markets. APF has lines of credit with three Canadian chartered banks that provide debt financing for acquisitions. The issue of new equity allows APF to pay down debt while continuing to make acquisitions. If Canadian debt or equity markets were to become inaccessible to APF, it may affect the ability of APF to continue to replace production and maintain distributions.

Changing government royalty regulations, income tax laws, incentive programs relating to the oil and gas industry and changes in securities legislation are all examples of regulatory changes that can affect APF's activities.

APF's cash flow is influenced by changes in a number of variables. Sensitivities to 2004 pre-hedging cash flows are as follows:

Variable	Change	Cash flow Impact ($000)	Change Per Unit
Crude oil price	$U.S. 1 per bbl	2,360	$0.07
Natural gas price	$Cdn. 0.10/mcf	1,200	$0.04
$U.S./$Cdn. exchange rate	$0.01	2,000	$0.06
Interest rate	1.00%	1,000	$0.03
Crude oil production	100 bbl/d	1,095	$0.03
Natural gas production	1 mmcf/d	1,500	$0.04

Critical Accounting Estimates

In order to prepare the financial statements in conformity with generally accepted accounting principles in Canada, APF has to make estimates and assumptions. The matters described below are considered to be the most critical in understanding the judgments that are involved in preparing the financial statements and the uncertainties that could impact the amounts reported on the results of operations, financial condition and cash flows. Accounting policies are described in Note 2 to the financial statements.

Estimation of oil and gas reserves

Oil and gas reserves have been estimated in accordance with National Instrument 51-101. Estimates of oil and gas reserves are inherently imprecise and represent only approximate amounts and are subject to future revision, as they are based on available reservoir data, prices and costs as of the date the estimate is made. Accordingly, the financial measures that are based on estimated reserves are also subject to change.

Depreciation, depletion and amortization

Proved reserves are used when calculating the unit-of-production rates used for depreciation, depletion and amortization for oil and gas assets including tangible fixed assets related to hydrocarbon production activities. The amount of depreciation is based on the units of production over the proved developed reserves of the relevant field during the time period. Unproved properties are amortized as required by particular circumstances. Other tangible fixed assets are generally depreciated on a straight-line basis over their estimated useful lives of five to ten years.

Ceiling test

The carrying amounts of fixed assets are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amounts for those properties may not be recoverable. If assets are determined to be impaired, the carrying amounts of those assets are written down to fair value. For this purpose, assets are assigned to a cost pool based on the country in which the activity has occurred. Estimates of future cash flows of assets related to hydrocarbon production activities are based on proved reserves determined in accordance with National Instrument 51-101.

Decommissioning and restoration costs

Provisions are held for the future decommissioning and restoration of oil and natural gas production facilities and pipelines at the end of their economic lives. Estimated decommissioning and restoration costs are based on current requirements, technology and price levels. Most of these obligations are many years in the future and the precise requirements that will have to be met are uncertain because technologies and costs as well as political, environmental, and safety expectations are subject to change.

RECENT ACCOUNTING AND REGULATORY GUIDELINE CHANGES

Full Cost Accounting Guideline

In September, 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost" to replace CICA Accounting Guideline 5. The new guideline proposes amendments to the ceiling test; as well, it requires additional disclosures relating to critical accounting estimates for impairment and depletion, depreciation and amortization.

The new guideline is effective for fiscal years beginning on or after January 1, 2004; however, APF has elected to adopt the standard early at December 31, 2003. There are no material financial impacts resulting from the adoption of this standard.

Asset Retirement Obligations

The Canadian Institute of Chartered Accountants ("CICA") issued Section 3110 "Asset Retirement Obligations" in March, 2003. The new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements. The Canadian standard will be effective for fiscal years beginning on or after January 1, 2004.

Under this standard, these obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over the life of the assets.

APF is currently evaluating the impact of this new standard and will adopt it during the first quarter of 2004.

Hedging Relationships

In December, 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003.

The new guideline addresses hedging transactions for the purposes of applying hedge accounting and establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue hedge accounting for positions hedged with derivatives.

A large portion of APF's current crude oil portfolio is a light sour or medium crude priced at Cromer and currently does not qualify as effective against the WTI light sweet crude price that APF currently hedges. As a result, APF does not anticipate applying hedge accounting against its existing crude oil hedge contracts.

In order for the currency hedge to qualify as effective, it must be associated with either U.S. denominated debt or U.S. denominated revenues. At December 31, 2003, APF did not have any U.S. denominated debt and the settlement terms for the foreign currency hedge is not aligned to the settlement dates of the WTI contracts. As a result, APF does not anticipate applying hedge accounting against its foreign currency hedge contracts.

The majority of APF's gas hedges are priced at AECO, which do correlate with existing gas revenue streams. APF is evaluating the impact of the standard with respect to gas contracts, and expects to finalize its decision to apply hedge accounting in the first quarter of 2004.

Variable Interest Entities

In June, 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. APF is assessing the impact of this new guideline.

Continuous Disclosure Rules

Effective March 30, 2004, all reporting issuers in Canada were to be subject to new continuous disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective, generally, for fiscal years beginning on or after January 1, 2004. The Instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and the Annual Information Form ("AIF").

The Instrument also proposes enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for APF to mail annual and interim financial statements and MD&A to unitholders, but rather, these documents are to be provided on an "as requested" basis. APF continues to assess the implications of this new instrument, which will be implemented at March 30, 2004.

Accounting for Convertible Debentures

In June, 2003, the CICA approved an amendment to Handbook section 3860 "Financial Instruments – Disclosure and Presentation". Under the previous guidelines, debt obligations that could be settled with the entity's own equity instruments could be classified as equity, and related interest was treated as a reduction of unitholders' equity.

The amendment would require certain obligations that must or could be settled with an entity's own equity instruments to be presented as a liability, with the corresponding interest being booked through the income statement. The amendment is effective for all fiscal years starting after November 1, 2004.

Outlook

APF remains committed to its strategy of buying well and exploiting its land base through development drilling, recompletions and field optimizations. For 2004, a total of 167 gross wells have been budgeted for drilling. APF has allocated $40 million to its capital expenditure budget for the year with 85% of the funds being directed to drilling and development of conventional properties. Throughout 2004, APF will continue to expand its CBM pilot projects in Central Alberta. In total, $7 million has been identified in the capital budget for CBM initiatives in both Canada and the U.S. With low production declines and the potential for higher rates of return than conventional production, APF feels CBM presents a very attractive opportunity and is ideally suited for the trust structure.

APF will continue to pursue acquisitions that will be accretive on a per unit basis to cash flow, production, reserves and net asset value. APF is committed to maintaining stable cash distributions over the long-term. In order to mitigate the commodity price risk that is inherent to the oil and gas sector, APF will continue to actively hedge production. APF believes that over the long term, outlook for both crude oil and natural gas pricing remains strong.

DISCLAIMER

Certain statements in this document are "forward-looking statements" including outlook on oil and gas prices, royalty rates, operating expenses, estimates of future production, estimated completion dates of construction and development projects, business plans for drilling and exploration, estimated amounts and timing of capital expenditures and anticipated future debt levels. Information concerning reserves contained in this material may also be deemed to be forward-looking statements as such estimates involving 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 Energy Trust and APF Energy Inc. These risks include, but are not limited to: the risks of the oil and gas industry (e.g., operational risks in exploration for, development and production of crude oil and natural gas, risks and uncertainties involving geology of oil and gas deposits; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; and health, safety and environmental risks); risks in conducting foreign operations (e.g., political and fiscal instability in nations where APF Energy does business); the possibility that government policies may change or governmental approvals may be delayed or withheld; and price and exchange rate fluctuations. These and other risks are described in APF Energy's reports that are on file with Canadian securities regulatory authorities. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors and management's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to APF or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. APF assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Computershare

530-8th Avenue S.W., Calgary, AB T2P 3S8 Tel.: (403) 267-6800 Fax: (403) 267-6529

April 21, 2004

Alberta Securities Commission
British Columbia Securities Commission
The Manitoba Securities Commission
New Brunswick Securities Commission
Newfoundland Securities Commission
Nova Scotia Securities Commission
Ontario Securities Commission
Prince Edward Island Securities Commission
Commission des valeurs mobilières du Québec
Saskatchewan Securities Commission
Canadian Venture Exchange (CDNX)
Toronto Stock Exchange

Dear Sirs:

Subject: **APF Energy Trust**

We confirm that the following material was sent by pre-paid mail on April 1 9, 2004 to the registered holders of the units of APF Energy Trust:

1. 2003 Annual Report
2. Notice of Meeting/Management Proxy Circular
3. Proxy
4. Proxy Return Envelope Canadian & US
5. Supplemental Mail Card

We further confirm that copies of the above mentioned materials, together with Supplemental Mail List Information included on the proxy, were sent by courier on April 19, 2004 to each intermediary holding Trust Units of the Trust who responded to the search procedures pusuant to Canadian Securities Administrators' National Instrument 54-101 regarding unit holder communications.

In compliance with regulations made under the Securities Act, we are providing this material to you in our capacity as trustee.

Yours truly,

COMPUTERSHARE TRUST COMPANY OF CANADA

"Signed by"
Angie Bains
Assistant Trust Officer
Corporate Trust Department

cc: APF Energy Trust
Attention: Alan MacDonald

FEE RULE

FORM 13-502F1
ANNUAL PARTICIPATION FEE FOR REPORTING ISSUERS

Reporting Issuer Name: **APF Energy Trust**

Participation Fee for the **Financial Year Ending:** **December 31, 2003**

Complete Only One of 1, 2 or 3:

1. Class 1 Reporting Issuers (Canadian Issuers – Listed in Canada and/or the U.S.)

Market value of equity securities:			
Total number of equity securities of a class or series outstanding at the end of the issuer's most recent financial year		34,074,240	
Simple average of the closing price of that class or series as of the last trading day of each of the months of the financial year (under paragraph 2.5(a)(ii)(A) or (B) of the Rule)	X	$12.54	
Market value of class or series	=	427,290,970	
			(A)
(Repeat the above calculation for each class or series of equity securities of the reporting issuer that are listed and posted for trading, or quoted on a marketplace in Canada or the United States of America at the end of the financial year)			(A)
Market value of corporate debt or preferred shares of Reporting Issuer or Subsidiary Entity referred to in Paragraph 2.5(b)(ii):		**144,466,000**	(B)
[Provide details of how determination was made.] **98,000,000 (LTD) +46,466,000 (Conv. Deb.)**			
(Repeat for each class or series of corporate debt or preferred shares)			(B)
Total Capitalization (add market value of all classes and series of equity securities and market value of debt and preferred shares) (A) + (B) =			**571,756,970**
Total fee payable in accordance with Appendix A of the Rule			35,000
Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)			0
Total Fee Payable x Number of months remaining in financial year year or elapsed since most recent financial year / 12			**$26,250**
Late Fee, if applicable (please include the calculation pursuant to section 2.9 of the Rule)			0

2. Class 2 Reporting Issuers (Other Canadian Issuers)

Financial Statement Values (use stated values from the audited financial statements of the reporting issuer as at its most recent audited year end):

Retained earnings or deficit ________

Contributed surplus ________

Share capital or owners' equity, options, warrants and preferred shares (whether such shares are classified as debt or equity for financial reporting purposes) ________

Long term debt (including the current portion) ________

Capital leases (including the current portion) ________

Minority or non-controlling interest ________

Items classified on the balance sheet between current liabilities and shareholders' equity (and not otherwise listed above) ________

Any other item forming part of shareholders' equity and not set out specifically above ________

Total Capitalization ________

Total Fee payable pursuant to Appendix A of the Rule ________

Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)

Total Fee Payable x Number of months remaining in financial year
year or elapsed since most recent financial year
12 ________

Late Fee, if applicable (please include the calculation pursuant to section 2.9 of the Rule) ________

3. Class 3 Reporting Issuers (Foreign Issuers)

Market value of securities:
If the issuer has debt or equity securities listed or traded on a marketplace located anywhere in the world (see paragraph 2.7(a) of the Rule):
Total number of the equity or debt securities outstanding at the end of the reporting issuer's most recent financial year ________

Simple average of the published closing market price of that class or series of equity or debt securities as of the last trading day of each of the months of the financial year on the marketplace on which the highest volume of the class or series of securities were traded in that financial year. X ________

Percentage of the class registered in the name of, or held beneficially by, an Ontario person X ________

(Repeat the above calculation for each class or series of equity or debt securities of the reporting issuer) = ________

Capitalization (add market value of all classes and series of securities) ________

Or, if the issuer has no debt or equity securities listed or traded on a marketplace located anywhere in the world (see paragraph 2.7(b) of the Rule):

Financial Statement Values (use stated values from the audited financial statements of the reporting issuer as at its most recent audited year end):

Retained earnings or deficit ________

Contributed surplus ________

Share capital or owners' equity, options, warrants and preferred shares (whether such shares are classified as debt or equity for financial reporting purposes) ________

Long term debt (including the current portion) ________

Capital leases (including the current portion) ________

Minority or non-controlling interest ________

Items classified on the balance sheet between current liabilities and shareholders' equity (and not otherwise listed above) ________
Any other item forming part of shareholders' equity and not set out specifically above ________

Percentage of the outstanding equity securities registered in the name of, or held beneficially by, an Ontario person X ________

Capitalization ________

Total Fee payable pursuant to Appendix A of the Rule ________

Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)

$$\text{Total Fee Payable} \times \frac{\text{Number of months remaining in financial year or elapsed since most recent financial year}}{12}$$ ________

Late Fee, if applicable
(please include the calculation pursuant to section 2.9 of the Rule) ________

Notes and Instructions

1. This participation fee is payable by reporting issuers other than investment funds that do not have an unregistered investment fund manager.

2. The capitalization of income trusts or investment funds that have no investment fund manager, which are listed or posting for trading, or quoted on, a marketplace in either or both of Canada or the U.S. should be determined with reference to the formula for Class 1 Reporting Issuers. The capitalization of any other investment fund that has no investment fund manager should be determined with reference to the formula for Class 2 Reporting Issuers.

3. All monetary figures should be expressed in Canadian dollars and rounded to the nearest thousand. Closing market prices for securities of Class 1 and Class 3 Reporting Issuers should be converted to Canadian dollars at the [daily noon] in effect at the end of the issuer's last financial year, if applicable.

4. A reporting issuer shall pay the appropriate participation fee no later than the date on which it is required to file its annual financial statements.

5. The number of listed securities and published market closing prices of such listed securities of a reporting issuer may be based upon the information made available by a marketplace upon which securities of the reporting issuer trade, unless the issuer has knowledge that such information is inaccurate and the issuer has knowledge of the correct information.

6. Where the securities of a class or series of a Class 1 Reporting Issuer have traded on more than one marketplace in Canada, the published closing market prices shall be those on the marketplace upon which the highest volume of the class or series of securities were traded in that financial year. If none of the class or series of securities were traded on a marketplace in Canada, reference should be made to the marketplace in the United States on which the highest volume of that class or series were traded.

7. Where the securities of a class or series of securities of a Class 3 Reporting Issuer are listed on more than one exchange, the published closing market prices shall be those on the marketplace on which the highest volume of the class or series of securities were traded in the relevant financial year.

APF ENERGY TRUST

NOTICE OF ANNUAL GENERAL AND SPECIAL MEETING OF UNITHOLDERS

TO: THE HOLDERS OF TRUST UNITS OF APF ENERGY TRUST

TAKE NOTICE that an Annual General and Special Meeting (the "Meeting") of the holders ("Unitholders") of trust units ("Trust Units") of APF Energy Trust (the "Trust") will be held at the Sun Life Plaza Conference Centre, Mezzanine Level, 140 – 4th Avenue S.W. Calgary, Alberta on Tuesday, the 18th day of May, 2004, at 3:00 p.m. (Calgary time) for the following purposes:

Annual Meeting

1. to receive and consider the consolidated financial statements of the Trust for the year ended December 31, 2003 and the auditors' report thereon;
2. to select directors of APF Energy Inc. ("Energy") and to fix the number of directors of Energy for the forthcoming year at six (6) directors;
3. to appoint auditors of the Trust and to authorize the directors of Energy to fix the remuneration of the auditors;

Special Meeting

4. to consider and, if thought fit, approve a resolution re-appointing Computershare Trust Company of Canada as the trustee of the Trust;
5. to consider and, if thought fit, approve a resolution to increase the maximum number of Trust Units issuable under the Trust Unit Incentive Rights Plan of the Trust;
6. to consider and, if thought fit, approve a special resolution to amend the trust indenture between Energy and Computershare Trust Company of Canada as trustee of the Trust, to delete the requirement of delivering to all Unitholders annual financial statements and MD&A and interim financial statements and MD&A unless a Unitholder has advised that such Unitholder wishes to receive the material;
7. to consider and, if thought fit, approve a special resolution to amend certain definitions in the royalty agreements by which royalties are granted to the Trust by Energy and APF Energy Limited Partnership;
8. to transact such other business as may properly be brought before the Meeting or any adjournment thereof.

The specific details of the matters proposed to be put before the Meeting are set forth in the Information Circular - Proxy Statement accompanying and forming part of this Notice.

Computershare Trust Company of Canada, the Trustee of the Trust, has fixed the record date for the Meeting at the close of business on April 16, 2004 (the "Record Date"). At the Meeting, Unitholders of record included in the list of Unitholders prepared as at the Record Date will be entitled to vote those Trust Units. No Unitholder who became a Unitholder after the Record Date will be entitled to vote at the Meeting.

Unitholders who are unable to attend the Meeting in person are requested to date and sign the enclosed Instrument of Proxy and to mail it to Computershare Trust Company of Canada Attention: Proxy Department, 9th Floor, 100 University Avenue, Toronto, Ontario M5J 2Y2. In order to be valid and acted upon at the Meeting, forms of proxy must be returned to the aforesaid address not less than 24 hours before the time set for the holding of the Meeting or any adjournment thereof.

DATED at Calgary, Alberta, this 2nd day of April, 2004.

BY ORDER OF COMPUTERSHARE TRUST COMPANY OF CANADA
By APF ENERGY INC.

(Signed) "Martin Hislop"
Chief Executive Officer

APF ENERGY

NEWS RELEASE
April 20, 2004

TSX: AY.UN
AY.DB

APF Energy Trust announces distribution of $0.175 per unit

APF Energy Trust announces it is maintaining its monthly distribution of $0.175 per unit. Payment will be made on May 17, 2004 to unitholders of record on April 30, 2004. The ex-distribution date is April 28 2004.

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.

For Further Information Please Contact

Steve Cloutier, President
Alan MacDonald, V.P. Finance
Christine Ezinga, Corporate Planning Analyst
Telephone: (403) 294-1000 ▲ Toll Free (800) 838 9206 ▲ Fax (403) 294-1010
Email: invest@apfenergy.com ▲ Internet: www.apfenergy.com

Computershare

530-8th Avenue S.W., Calgary, AB T2P 3S8 Tel.: (403) 267-6800 Fax: (403) 267-6529

April 21, 2004

Alberta Securities Commission
British Columbia Securities Commission
The Manitoba Securities Commission
New Brunswick Securities Commission
Newfoundland Securities Commission
Nova Scotia Securities Commission
Ontario Securities Commission
Prince Edward Island Securities Commission
Commission des valeurs mobilières du Québec
Saskatchewan Securities Commission
Canadian Venture Exchange (CDNX)
Toronto Stock Exchange

Dear Sirs:

Subject: **APF Energy Trust**

We confirm that the following material was sent by pre-paid mail on April 1 9, 2004 to the registered holders of the units of APF Energy Trust:

1. 2003 Annual Report
2. Notice of Meeting/Management Proxy Circular
3. Proxy
4. Proxy Return Envelope Canadian & US
5. Supplemental Mail Card

We further confirm that copies of the above mentioned materials, together with Supplemental Mail List Information included on the proxy, were sent by courier on April 19, 2004 to each intermediary holding Trust Units of the Trust who responded to the search procedures pusuant to Canadian Securities Administrators' National Instrument 54-101 regarding unit holder communications.

In compliance with regulations made under the Securities Act, we are providing this material to you in our capacity as trustee.

Yours truly,

COMPUTERSHARE TRUST COMPANY OF CANADA

"Signed by"
Angie Bains
Assistant Trust Officer
Corporate Trust Department

cc: APF Energy Trust
Attention: Alan MacDonald

APF ENERGY TRUST

TO Unitholders of APF Energy Trust

National Instrument 51-102 provides registered and beneficial securityholders with the opportunity to elect annually to have their name added to an issuer's supplemental mailing list in order to receive annual financial statements and Management's Discussion & Analysis thereon ("MD&A") and/or interim financial statements and MD&A of the Issuer. If you are interested in receiving such statements and MD&A please complete and return this form.

PLEASE RETURN TO:

APF ENERGY TRUST
c/o Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto Ontario M5J 2Y2

NAME: (Please Print) ______________________________

ADDRESS: ______________________________

____

____

I wish to receive ☐ Annual Financial Statements and MD&A

(check applicable box(es)) ☐ Interim Financial Statements and MD&A

SIGNATURE: ____________________ **DATE:** ____________

CUSIP Number: 00185T202
Code: APFQ

APF ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

For the Year Ended December 31, 2003

April 15, 2004

APF ENERGY TRUST
2100, 144 - 4th Avenue SW
Calgary, Alberta T2P 3N4
Telephone: (403) 294-1000 Toll Free: (800) 838-9206 Fax: (403) 294-1074
Internet: www.apfenergy.com e-mail: invest@apfenergy.com

TABLE OF CONTENTS

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"APF Energy"	APF Energy Inc.	**"Tika"**	Tika Energy Inc.
"APF Partnership"	APF Energy Limited Partnership	**"Unitholders"**	holders of Trust Units of the Trust
"ARTC"	Alberta Royalty Tax Credit		
"bbls"	barrels	**"mcf"**	1,000 cubic feet
"mbbl"	1,000 barrels	**"mmcf"**	1,000,000 cubic feet
"bbl/d"	barrels per day	**"bcf"**	1,000,000,000 cubic feet
"GJ"	Gigajoule = 0.95 mcf	**"mcf/d"**	one thousand cubic feet per day
"m^3"	cubic metre volume	**"mmcf/d"**	one million cubic feet per day
"NGL"	natural gas liquids	**"mmbtu"**	one million BTUs
"9.40% Debentures"	convertible unsecured subordinated debentures of the Trust maturing July 31, 2008	**"boe"**	barrels of oil equivalent
		"mboe"	1,000 barrels of oil equivalent
"Special Unitholders"	holders of special voting units of the Trust	**"boe/d"**	barrels of oil equivalent per day
		"BTU"	British thermal unit
"Trust"	APF Energy Trust		

"APF Report" the report of Gilbert Laustsen Jung Associates Ltd. ("GLJ"), independent petroleum consultants, dated March 16, 2004 and effective January 1, 2004, evaluating 100% of the Canadian reserves of APF Energy and APF Partnership, using GLJ (2004-01) pricing. The report includes the interests of Tika Energy Inc. located in the United States. These interests were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") and were consolidated with the GLJ evaluated properties to generate corporate total forecasts. The interests evaluated by McDaniel are very minor relative to the overall corporate reserves and value portfolio and account for 3.7% and 1.4% of the corporate total proved plus probable (on a boe basis) and discounted present value at 10%, respectively.

"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.

ADDITIONAL INFORMATION

Additional information, including Directors' and Executive Officers' remuneration and indebtedness, principal holders of the Trust's securities and options and rights to purchase the Trust's securities, and interest of insiders in material transactions, if applicable, is contained in the Trust's Management Information Circular dated April 2, 2004, in connection with the Annual General and Special Meeting of Unitholders of the Trust to be held on May 18, 2004, which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Trust and the business environment in which the Trust operates is provided in the Trust's Management Discussion and Analysis and comparative Consolidated Financial Statements for the fiscal year ended December 31, 2003 found on pages 33 to 45 and 48 to 63 respectively, of the 2003 Annual Report to the Unitholders, which information is incorporated herein by reference.

The Trust will provide to any person upon request:

1. When securities of the Trust are in the course of a distribution under a preliminary short form prospectus or short form prospectus:

   (a) One copy of this Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated herein by reference;

   (b) One copy of the comparative Consolidated Financial Statements of the Trust for the year ended December 31, 2003, together with the report of the auditors thereon, and one copy of any interim financial statement of the Trust issued subsequent to the annual financial statements;

   (c) One copy of the Management Information Circular and Proxy Statement of the Trust dated April 2, 2004, in connection with the Annual General and Special Meeting of the Unitholders of the Trust to be held on May 18, 2004; or

(d) One copy of any other document or report which is incorporated by reference into the preliminary short form prospectus or short form prospectus and is not required to be provided under paragraphs (a), (b) or (c) above.

2. At any other time, one copy of any document referred to in paragraphs 1(a), (b) and (c) above, provided that the Trust may require the payment of a reasonable charge from such person or company who is not a Unitholder of the Trust.

Requests for information should be made to:

APF Energy Inc.
2100, 144-4th Avenue S.W.
Calgary, Alberta T2P 3N4
Attention: Secretary
Telephone: (403) 294-1000 Toll Free: (800) 838-9206 Fax: (403) 294-1074
Internet: www.apfenergy.com e-mail: invest@apfenergy.com

SPECIAL NOTE REGARDING FORWARD LOOKING INFORMATION

Certain statements in this document or incorporated herein by reference may constitute "forward-looking statements". These forward-looking statements can generally be identified as such because of the context of the statements, including words such as the Trust "believes", "anticipates", "expects" or words of a similar nature. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Trust, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others, the following:

- the performance characteristics of the properties of APF Energy, APF Partnership and Tika;
- oil and natural gas reserve quantities and the discounted present value of these reserves;
- the amount and nature of capital expenditures;
- plans for drilling wells;
- prices for oil and natural gas produced and the impact of changes in prices on cash flow after hedging;
- timing and amount of future production;
- operating and other costs;
- expectations regarding the ability to raise capital and to continually add reserves through acquisitions and developments;
- business strategies and plans of management; and
- prospect development and acquisitions.

Such forward looking statements are subject to risks, uncertainties and other factors, many of which are beyond our control, including:

- the timing and success of integrating the business and operations of acquired assets and companies;
- the impact of general economic conditions;
- industry conditions, including fluctuations in the price of oil and natural gas, royalties payable in respect of our oil and natural gas production, and changes in governmental regulation of the oil and natural gas industry, including environmental regulation;
- uncertainty of estimates of oil and natural gas reserves;
- impact of competition, availability and cost of seismic, drilling and other equipment;
- operating hazards and other difficulties inherent in the exploration for and production and sale of oil and natural gas;
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- uncertainties as to the availability and cost of financing.

These factors should not be considered exhaustive. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, these forward looking statements. See also the matters discussed under "Risk Factors" on page 32.

THE TRUST AND ITS SUBSIDIARIES

APF Energy Trust

The Trust is an open-end investment trust formed under the laws of the Province of Alberta on October 10, 1996 and governed by an amended and restated trust indenture dated January 3, 2003 (the "Trust Indenture"). The principal office of the Trust is located at 2100, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4. The trust units ("Trust Units") and the 9.40% Debentures of the Trust are listed and posted for trading on the Toronto Stock Exchange under the symbols "AY.UN" and "AY.DB" respectively. Computershare Trust Company of Canada (the "Trustee") is the trustee of the Trust and the holders of Trust Units are the sole beneficiaries of the Trust.

The Trust was initially formed for the purpose of issuing Trust Units to the public and using the funds so raised to purchase royalties on oil and natural gas properties. The Trust is authorized to acquire, directly or indirectly, energy related assets and properties and securities of oil and gas entities.

The Trust's primary assets are royalties (collectively the "Royalties" and individually a "Royalty") granted by APF Energy and APF Partnership on their respective oil and gas properties. Each of the Royalties consists of an entitlement to 99% of the royalty income from the oil and gas properties after deduction of certain costs, expenditures and deductions.

The goal of the Trust is to provide holders of Trust Units with high and stable cash distributions by continually replacing and adding to the reserves held by APF Energy, APF Partnership and other entities granting a Royalty to the Trust, through acquisition, drilling and optimization initiatives.

APF Energy Inc.

APF Energy is a wholly owned subsidiary of the Trust. It was incorporated pursuant to the *Business Corporations Act* (Alberta) on December 8, 1995 as 677633 Alberta Inc. By Articles of Amendment filed May 8, 1996, its name was changed to APF Energy Inc. The business of APF Energy is the acquisition, development, exploitation and disposition of oil and natural gas properties and the granting of a Royalty to the Trust. Since incorporation it has amalgamated from time to time with subsidiary corporations acquired in conjunction with acquisitions of oil and natural gas properties. The amalgamated corporation continues under the name APF Energy Inc. APF Energy also provides all necessary management, administrative and advisory services to the Trust, APF Acquisition Trust and to APF Partnership and its general partner, 990009 Alberta Inc. At December 31, 2003, APF Energy had 70 employees. The principal office of APF Energy is located at 2100, 144 - 4th Avenue S.W., Calgary, Alberta T2P 3N4 and its registered office is located at 3400, 150 – 6th Avenue S.W., Calgary, Alberta, T2P 3Y7.

APF Acquisition Trust

APF Acquisition Trust is an open-end unincorporated commercial trust formed under the laws of the Province of Alberta pursuant to a trust agreement dated May 30, 2002 and is wholly owned by the Trust. The asset of APF Acquisition Trust is a 99% limited partnership interest in APF Partnership. The head and principal office of APF Acquisition Trust is located at 2100, 144 - 4th Avenue S.W., Calgary, Alberta T2P 3N4.

APF Energy Limited Partnership

APF Partnership is a limited partnership formed under the laws of the Province of Alberta and is governed by an amended and restated limited partnership agreement dated May 30, 2002. 990009 Alberta Inc., a wholly owned subsidiary of the Trust is the general partner of and has a 1% interest in the limited partnership. APF Acquisition Trust, through its trustee, is the limited partner and has a 99% interest in the limited partnership. The head and principal office of APF Partnership is located at 2100, 144 – 4th Avenue S.W., Calgary, Alberta T2P 3N4.

990009 Alberta Inc.

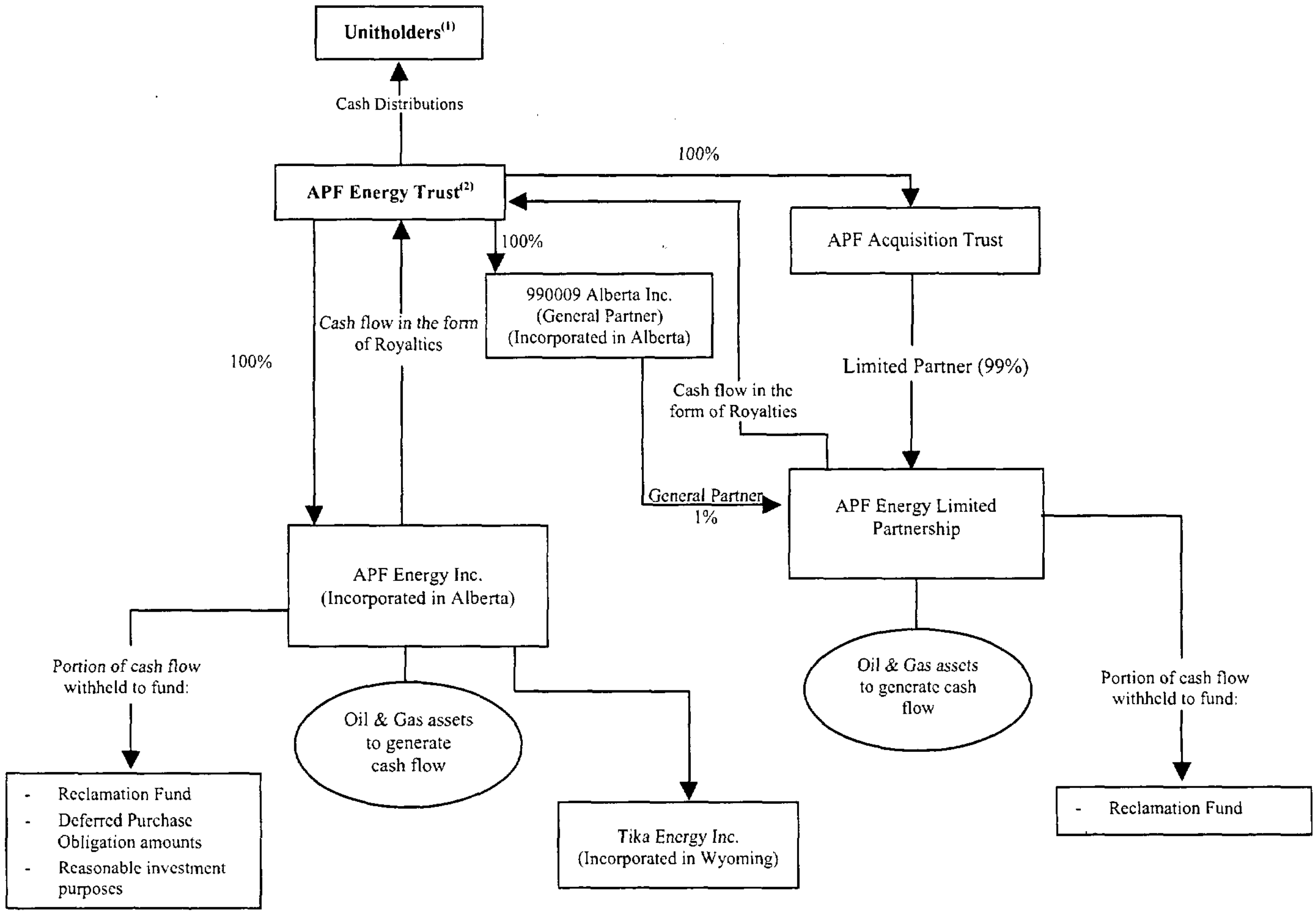
990009 Alberta Inc. is a wholly owned subsidiary of the Trust. It was incorporated pursuant to the *Business Corporations Act* (Alberta) on May 21, 2002. It is the general partner of APF Partnership and its only asset is a 1% interest in APF Partnership. The principal office of 990009 Alberta Inc. is located at 2100, 144 – 4th Avenue S.W., Calgary, Alberta T2P 3N4 and its registered office is located at 3400, 150 – 6th Avenue, S.W., Calgary, Alberta T2P 3Y7.

Tika Energy Inc.

Tika is a company formed under the laws of Wyoming on September 14, 1999. APF Energy carries on its operations in the United States through Tika. Tika is a wholly-owned subsidiary of APF Energy following the amalgamation of APF Energy and CanScot Resources Ltd. on October 1, 2003. The principal office of Tika is located at 2100, 144 - 4th Avenue S.W., Calgary, Alberta, T2P 3N4 and its registered office is located at 159 N. Wolcott, Ste. 330, Casper, Wyoming 82601.

Organization Chart

The following diagram illustrates the relationships between the Trust and its subsidiaries and the flow of cash from the oil and gas properties to the Trust and from the Trust to the Unitholders.



Notes:

(1) The Unitholders own 100% of the equity of the Trust.

(2) The Trust also had outstanding at December 31, 2003 $48.785 million of 9.40% Debentures with a maturity date of July 31, 2008. See "Securities of the Trust - Convertible Debentures".

GOVERNANCE OF THE TRUST

The Trustee and APF Energy

Pursuant to the Trust Indenture, Computershare Trust Company of Canada (the "Trustee") has been appointed as trustee of the Trust. The Trustee has no beneficial interest in the Trust and holds the Trust's assets and exercises its powers for the benefit of Unitholders. The Trustee has the authority to exercise all rights, powers and privileges in respect of the assets of the Trust excepting matters relating to the maximization of Unitholder value in the context of a response to an offer for Trust Units or for all or substantially all of the assets of the Trust or any subsidiary of the Trust (an "Offer"). APF Energy has the authority to exercise rights, powers and privileges in relation to an Offer.

The Trust Indenture gives the Trustee the authority to delegate to a manager such power and authority as the Trustee in its sole discretion deems necessary or desirable to effect the actual administration of the duties of the Trustee under the Trust Indenture, without regard to whether such power or authority is normally granted or delegated by trustees. Pursuant to this authority, the

Trustee has entered into an agreement (the "Administrative Services Agreement") under which APF Energy provides management, administrative and advisory services to the Trust. In addition, the Trust Indenture delegates to APF Energy responsibility for any and all matters relating to the redemption of Trust Units, the negotiation of management agreements in relation to assets of the Trust and any issuance or offering of Trust Units or any securities to purchase, to convert into or exchange into Trust Units.

As a consequence, all of the significant management decisions of the Trust have been delegated to APF Energy and are carried out through its Board of Directors and management and employees.

Bank of Montreal Trust Company was appointed trustee of the Trust for an initial term which expired in 1999. The Trustee subsequently acquired the stock transfer business of Bank of Montreal Trust Company and in 2002, the Unitholders approved the appointment of the Trustee as successor trustee of the Trust. A decision to reappoint, or to appoint a successor to, the Trustee is made by ordinary resolution at each annual meeting of Unitholders. The Trustee may resign on 60 days notice to APF Energy and may be removed on notice from APF Energy and approved by Special Resolution of Unitholders if the Trustee is no longer qualified to act as trustee or becomes bankrupt or insolvent or upon certain other events such as liquidation seizure of the Trustee's assets. The Trustee receives a fee for acting as trustee of the Trust and is entitled to reimbursement for all costs, charges and expenses incurred by the Trustee in connection with the management and administration of the Trust. The Trust Indenture provides that the Trustee and its directors, officers, employees, shareholders and agents will not be liable to Unitholders or others in connection with any matter pertaining to the Trust, subject to exceptions for liability resulting from gross negligence, willful default or fraud. In addition, the Trustee and its directors, officers, employees shareholders and agents are indemnified for all liabilities incurred in carrying out any of the Trustee's duties and responsibilities, exercising any power, authority or discretion given to it under the Trust Indenture and for all other liabilities, losses, costs, charges, taxes, damages, expenses, penalties and interest in respect of taxes and all other expenses and liabilities incurred in respect of the administration of the Trust, including, specifically, environmental liabilities and damages.

The Unitholders

At each annual meeting of Unitholders, Unitholders and Special Unitholders are entitled to vote for the reappointment of the Trustee (or for the appointment of a successor trustee), for the selection of persons to be appointed as directors of APF Energy, and for the appointment of the auditor of the Trust. Unitholders are also entitled to vote on any change in the auditor of the Trust. All of the foregoing actions require an ordinary resolution of Unitholders. An ordinary resolution is a resolution approved at a meeting of Unitholders by more than 50% of the votes of Unitholders and Special Unitholders cast in respect of the resolution. Unitholders and Special Unitholders are also entitled to vote on any matter required by the Trust Indenture to be approved by Special Resolution. In general, a Special Resolution is required to authorize any amendment to the Trust Indenture (other than amendments required to comply with applicable laws or amendments which are not inconsistent with or do not materially affect the substance of the Trust Indenture), amendments to certain material contracts of the Trust, any subdivision or consolidation of the Trust Units, any sale or transfer of all or substantially all of the assets of the Trust or the dissolution of the Trust. A special resolution is a resolution proposed to be passed as a special resolution and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units represented at the meeting and voted on a poll upon the resolution.

Unitholders and Special Unitholders are not entitled to interfere with or give any direction to the Trustee or APF Energy with respect to the affairs of the Trust or in connection with the exercise of any powers or authorities conferred upon the Trustee or APF Energy under the Trust Indenture or the Administrative Services Agreement and have no right of ownership in any of the assets of the Trust or to compel or call for any partition, division, dividend or distribution of the any of the assets of the Trust.

SECURITIES OF THE TRUST

Securities

Trust Units and Special Voting Units

The Trust is authorized to issue a maximum of 500 million trust units ("Trust Units"). The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units share equally in all distributions from the Trust and all Trust Units carry equal voting rights at meetings of holders of Trust Units ("Unitholders"). The Trust is also authorized to issue an unlimited number of special voting units ("Special Voting Units") entitling the holders ("Special Unitholders") to the number of votes at meetings of Unitholders as is prescribed by the Board of Directors of APF Energy in the resolution authorizing issuance of the Special Voting Units. The Special Voting Units do not confer any other rights on the Special Unitholders. None of the Special Voting Units have been issued.

Trust Units and Special Voting Units, including rights, warrants or other securities to purchase, to convert into or exchange into Trust Units and Special Voting Units, may be issued on terms and conditions and at such time or times as APF Energy may determine. Trust Units may only be issued when fully paid and the Unitholders may not thereafter be required to make any further contribution to the Trust with respect to such Trust Units. Trust Units may be issued for a consideration payable in installments if represented by installment receipts until final payment is made.

Meetings and Voting

The Trust Indenture requires the holding of annual meetings of Unitholders. Special meetings of Unitholders may be called at any time by the Trustee and are required to be called by the Trustee upon the written request of Unitholders holding in aggregate not less than 20% of the Trust Units. Notice of all meetings of Unitholders is required to be given to Unitholders at least 21 days prior to the meeting. Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder or Special Unitholder. Two persons present in person or represented by proxy and representing in the aggregate not less than 10% of the votes attaching to all outstanding Trust Units constitute a quorum for the transaction of business at all such meetings. Unitholders are entitled to one vote per Trust Unit at all meetings of Unitholders.

Redemption Right

A Unitholder may require the Trust, at any time on the demand of the Unitholder, to redeem his or her Trust Units for an amount equal to the lesser of (a) 95% of the market price of the Trust Units on the Toronto Stock Exchange, or if not trading on the Toronto Stock Exchange at such time, the principal market on which the Trust Units are quoted for trading at such time (the "Principal Market"), during the 10 day trading period commencing immediately after the date on which the Trust Units were tendered for redemption, and (b) 95% of the closing market price on the Principal Market on which the Trust Units are quoted for trading on the date that the Trust Units were tendered for redemption. For the purposes of (a), the market price is an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that if the Principal Market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price will be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the Principal Market for fewer than five of the 10 trading days, the market price will be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the Principal Market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the Principal Market provides only the highest and lowest prices of Trust Units traded on a particular day. For the purposes of (b), the closing market price will be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of Trust Units if there was trading and the Principal Market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date. Upon redemption, all of such Unitholder's rights to and under the Trust Units tendered for redemption are surrendered. The obligations of the Trust to redeem Trust Units is subject to a monthly aggregate cash cap for all Trust Units tendered for redemption in such month of $100,000 and an aggregate cash cap for all Trust Units tendered for redemption in a six month period of $500,000. The Board of Directors of APF Energy may waive these limitations and is required to waive them in circumstances where Trust Units held in trusts governed by registered plans under the *Income Tax Act* (Canada) would not otherwise be entitled to receive cash payment for the Trust Units redeemed. The price payable by the Trust on redemption may be satisfied by cash payment or, in certain circumstances, including where such payment would cause the monthly or six month cash cap to be exceeded, by way of an *in specie* distribution (that is, a proportionate distribution of the assets of the Trust).

Distributions

The Trust makes pro rata cash distributions to Unitholders on a monthly basis. Distributions are generally announced via news release during the third week of the month and Unitholders of record on the last day of that month are entitled to participate in the distribution. Distributions are paid by the Trustee to the Unitholders 15 days following the distribution record date or, if such date is not a business day, on the next business day. Distributions in any month consist of income from Royalties, ARTC and other income received by the Trust during the preceding month less royalties, expenses and withholdings payable by the Trust and less other amounts reasonably determined by APF Energy to be retained for the purposes of the Trust. In the past, the Trust has retained income to, among other things, fund capital expenditure or acquisitions, stabilize future distributions or advance funds to APF Energy to temporarily reduce its indebtedness to its bankers. During 1997 (the first year during which the Trust made distributions), 61% of cash distributions were tax deferred and for income tax purposes were treated as a return of capital, while the same figures for 1998, 1999, 2000, 2001 and 2002 were 75%, 66%, 38%, 43% and 36%, respectively. For 2003 cash distributions, 21% will not be subject to tax with 79% being taxable to Unitholders.

The following per Trust Unit cash distributions have been received by Unitholders during the periods indicated:

Trust Unit Cash Distributions	
1997	$1.510
1998	$1.840
1999	$1.555
2000	$1.900
2001	$3.045
2002	$1.800
2003	
January	$0.160
February	$0.160
March	$0.165
April	$0.185
May	$0.185
June	$0.200
July	$0.200
August	$0.200
September	$0.200
October	$0.175
November	$0.175
December	$0.175
2003 Total	$2.180
2004	
January	$0.175
February	$0.175
March	$0.175
April	$0.175
	$0.700
Grand Total	$14.530

Note:

(1) The initial public offering of the Trust was completed on December 17, 1996. The first cash distribution was made to Unitholders on January 31, 1997.

Limitations On Non-Resident Ownership

At no time may more than one-half of the outstanding Trust Units be held by non-residents of Canada ("non-residents") within the meaning of the *Income Tax Act* (Canada). If at any time the Trustee becomes aware that the beneficial owners of 49% of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trustee may make a public announcement to that effect and will not accept a subscription for Trust Units from or issue or register a transfer of Trust Units to a person unless the person provides a declaration in a form prescribed by the Trustee that the person is not a non-resident. If, notwithstanding the foregoing, the Trustee determines that a majority of the Trust Units are held by non-residents, the Trustee may send a notice to non-resident holders of Trust Units, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring them to sell their Trust Units or a specified portion thereof within a specified period of not less than 60 days. If the Unitholders receiving notice have not within the period sold the specified number of Trust Units or provided the Trustee with satisfactory evidence that they are not non-residents, the Trustee may on behalf of such Unitholders sell such Trust Units and, in the interim, will suspend the voting and distribution rights attached to such Trust Units. Any sale will be made on any stock exchange on which the Trust Units are then listed and, upon the sale, the affected holders will cease to be holders of Trust Units and their rights will be limited to receiving the net proceeds of sale upon surrender of the Certificates representing such Trust Units.

Take-over Bids – Compulsory Acquisition

The Trust Indenture provides that if a person ("Offeror") makes a take-over bid ("Offer") to purchase the outstanding Trust Units and the Offer is accepted by the holders of not less than 90% of the outstanding Trust Units not owned by or on behalf of the Offeror or an affiliate or associate of the Offeror, the Offeror has the right, but is not obligated, to acquire the remaining Trust

Units held by persons who did not accept the Offer or by subsequent transferees of such persons (collectively, the "Dissenting Offerees")

To exercise the right, the Offeror must give notice (the "Offeror's Notice") by registered mail to each Dissenting Offeree of the proposed acquisition within 60 days after the termination of the Offer, and in any event within 180 days after the date of the Offer. Within 20 days of giving the Offeror's Notice, the Offeror must pay or transfer to the Trust the amount of money or other consideration the Offeror would have had to pay or transfer to the Dissenting Offerees if they had elected to accept the Offer. Money or other consideration so paid or transferred is to be held in trust for the Dissenting Offerees. Within 30 days after receipt of the Offeror's Notice, provided that the Offeror has then paid or transferred to the Trust the money or other consideration as required, the Trust is required to issue the Offeror a certificate for the Trust Units that were held by Dissenting Offerees and cause the transfer agent of the Trust Units to enter the Offeror on the register of Unitholders as the holder of such Trust Units and to remove the Dissenting Offeree from the register of Unitholders. Thereafter, Dissenting Offerees who send or deliver certificates for Trust Units to the Trustee are entitled to receive the money or other consideration to which he is entitled, disregarding fractional Trust Units.

Unitholder Rights Plan

The Trust entered into a Unitholders' Rights Plan Agreement ("URP") made as of April 19, 2003 between the Trust and Computershare Trust Company of Canada, as rights agent (the "Rights Plan"). The URP replaced a similar plan which expired April 19, 2003.

The primary objective of the URP is to provide the Board of Directors of APF Energy with sufficient time to consider and, if appropriate, explore and develop alternatives for maximizing Unitholder value in the event that a take-over bid is made for the Trust, and to provide every Unitholder with an equal opportunity to participate in such a bid. The URP is intended to regulate certain aspects of take-over bids for the Trust but it is not intended to impede a bona fide attempt to acquire control of the Trust, if an offer is made fairly.

Distribution Reinvestment Plan

On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003.

The DRIP allows eligible Unitholders to direct that their monthly cash distributions be reinvested in additional Trust Units at 95% of the average market price (as defined in the DRIP) on the applicable distribution date. The DRIP includes a feature which allows eligible Unitholders to elect, under the premium distribution component of the DRIP, to have these additional Trust Units delivered to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such Unitholders would have otherwise been entitled to receive on the applicable distribution date. The DRIP also allows those Unitholders who participate in either the distribution reinvestment component or the premium distribution component of the DRIP to purchase additional Trust Units from treasury for cash at a purchase price equal to the average market price (with no discount) in minimum amounts of $1,000 per remittance and up to $100,000 aggregate amount of remittances by a Unitholder in any calendar month, all subject to an overall annual limit of 2% of the outstanding Trust Units.

Convertible Debentures

On July 3, 2003, the Trust completed a public offering of the 9.40% Debentures for gross proceeds of $50 million. The 9.40% Debentures bear interest at an annual rate of 9.40% payable semi-annually on January 31 and July 31 in each year commencing January 31, 2004. The 9.40% Debentures are redeemable by the Trust at a price of $1,050 if redeemed on or after July 31, 2006 and before July 31, 2007 and at a price of $1,025 if redeemed on or after July 31, 2007 and before maturity, in each case together with accrued and unpaid interest. The 9.40% Debentures are convertible into Trust Units at the option of the holder at any time prior to the close of business on the earlier of maturity and the business day preceding the date specified by the Trust for redemption of the 9.40% Debentures, at a conversion price of $11.25 per Trust Unit. The Trust may elect, from time to time, to satisfy its obligation to pay interest on the 9.40% Debentures, by delivering sufficient Trust Units to the debenture trustee for sale in order to satisfy the cash interest payment to holders. The Trust may also satisfy its obligation to pay the principal owing on redemption or maturity by the issue of Trust Units at a deemed price of 95% of the weighted average trading price of the Trust Units preceding the redemption or maturity date. As at December 31, 2003, $1.2 million principal amount of the 9.40% Debentures had been converted.

A more complete description of the 9.40% Debentures and their terms is set out under the heading "Description of Debentures" in the prospectus of the Trust dated June 26, 2003, which information is incorporated by reference herein.

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Trust was formed on October 10, 1996 for the purpose of acquiring a Royalty from APF Energy on its oil and gas properties from time to time. The Trust completed an initial public offering of 3.5 million Trust Units at $10 per Trust Unit on December 17, 1996. The Trust used a portion of the proceeds to acquire the Royalty on properties acquired by APF Energy in 1996 at Rosebank, Grande Prairie, Sibbald, Countess - Leckie and Westerose for the sum of $17.86 million. The Trust has subsequently completed a number of offerings of Trust Units and has acquired a Royalty on a number of additional properties. Effective July 28, 1999, the Trust was converted to an open-end trust to provide greater flexibility to make value-enhancing acquisitions. The investments that may be made by the Trust were expanded from the acquisition and holding of royalties on petroleum and natural gas properties and related assets to include the acquisition and holding of various forms of energy-related assets (for example, the shares of an oil and gas company or petroleum and natural gas related facilities without associated properties, energy marketing companies or assets or midstream or downstream companies) and the securities of entities holding such assets (which may include securities of a trust or securities of a wholly-owned subsidiary corporation).

Acquisitions

Since it commenced business in 1996, APF Energy has acquired petroleum and natural gas assets in Western Canada and Wyoming in a number of transactions. Those completed since January 1, 2001 are summarized below:

Date	Transaction
April 2001	Corporate acquisition of Alliance Energy Inc.
April 2001	Acquisition of assets from third party in Southeast Saskatchewan
August 2001	Acquisition of assets from a third party at Sakwatamau
May 2002	Acquisition of Kinwest Resources Inc. and 987687 Alberta Ltd.
December 2002	Acquisition of Paddle River Property
December 2002	Internalization of management
February 2003	Corporate acquisition of Hawk Oil Inc.
April 2003	Corporate acquisition of Nycan Energy Corp.
May 2003	Acquisition of assets at Countess
June 2003	Acquisition of assets in the Swan Hills Unit No. 1 and certain non-unit rights
September 2003	Corporate acquisition of CanScot Resources Ltd.

Certain of the properties acquired in May, 2002 were subsequently transferred to APF Partnership and APF Partnership granted a Royalty to the Trust. In addition to the foregoing, reserves have been added through optimization initiatives and drilling on its various properties, as well as through minor acquisitions.

APF Energy will continue to pursue both oil and gas asset and corporate acquisitions. These transactions will be financed through a combination of credit facilities, available working capital and the proceeds from future issues of Trust Units. The objectives are to: (1) acquire assets that will generate a high rate of return for Unitholders; (2) acquire assets with upside potential, where the value can be maximized through optimization, low-risk drilling and improvements to infrastructure; (3) seek opportunities to act as operator of the properties, which will allow the corporation to control the timing and cost of optimization, drilling and maintenance initiatives; (4) manage risk through commodity, currency and interest rate hedging and oil and gas marketing strategies, to ensure that Unitholders receive above-average cash distributions; (5) keep administrative costs low by running an efficient management structure; (6) grow the Trust to improve liquidity and create a more effective market in which investors of the Trust can buy or sell Trust Units.

CBM Operations

Through the purchase of CanScot, APF Energy acquired interests in coalbed methane ("CBM") projects in both Alberta and northeast Wyoming. The CBM industry has been active in the United States since the 1980s. The CBM industry in Canada has only recently begun to develop, with current production in Alberta only at nominal levels.

At present, there are two general types of CBM projects being developed in Alberta. The more prevalent of these requires wells to be de-watered in order to allow for the gas to be produced, while the second involves coals where there is virtually no water production. APF Energy has exposure to both types of CBM plays.

A CBM program typically involves three stages. The first involves the drilling of a single well to test for permeability and gas content. Once this is established, the second phase comprises the drilling of four to six wells in a pilot program, to establish additional parameters that ultimately lead to the final stage of full-scale commercial development through the drilling of multiple wells.

In Alberta, APF Energy's land holdings in central Alberta are prospective for CBM in the Mannville formation, which requires de-watering. The de-watering process can take between six to twelve months, depending upon well density, with produced water re-injected to an appropriate disposal formation. Currently APF Energy has two major projects in this area at Corbett and Doris, where the company has been adding to the land position it acquired through the CanScot transaction. Operations are in various stages of development with the drilling of several test wells and the implementation of a full ten well pilot program at Corbett.

Elsewhere in Alberta, APF Energy has been evaluating lands prospective for the other, "dry" CBM play in the Horseshoe Canyon formation of east and south central Alberta. Currently, APF Energy has no active pilot project in this area but is preparing to drill individual test wells to evaluate commerciality.

In the Powder River Basin of Wyoming, APF Energy is involved in four active CBM projects. At Big Bend in Converse County the company has recently confirmed permeability and gas content with its initial test wells and an eight well pilot project is now underway. Like the Mannville CBM play in central Alberta, wells in this area must be de-watered for an extensive period prior to the onset of commercial gas production. In contrast to the re-injection operation in effect in Alberta, water in Wyoming is potable and is therefore produced to surface and is often collected in disposal ponds. APF Energy and other energy companies engaged in the CBM business continually monitor water quality to ensure that all disposal operations comply with environmental regulations.

CBM is becoming increasingly competitive, and APF Energy will be required to compete with other companies, many of which have greater resources, in order to acquire assets and lands that are prospective for CBM, in both Alberta and Wyoming.

Significant Acquisitions During 2003

During the financial year ended December 31, 2003, the Trust completed two significant acquisitions, being the corporate acquisitions of Hawk Oil Inc. ("Hawk") and Nycan Energy Corp. ("Nycan") and several other acquisitions, each of which is summarized below. None of the transactions involved insiders, associates or affiliates of the Trust, except the acquisition of CanScot, as discussed below.

Acquisition of Hawk Oil Inc.

On February 5, 2003, APF Energy completed the acquisition of all of the issued and outstanding common shares of Hawk Oil Inc. ("Hawk") for $2.856 million cash and the issuance of 3,990,461 Trust Units. APF Energy also assumed approximately $8.5 million of net debt of Hawk. APF Energy and Hawk were amalgamated effective February 7, 2003. The acquisition added production of approximately 2,700 boe/d, comprised of 9.3 mmcf/d of natural gas, and 1,150 bbl/d of oil and NGLs.

Further information regarding Hawk was set out in the Renewal Annual Information Form of the Trust dated May 15, 2003 under the heading "Material Events Announced before Year-End - Acquisition of Hawk Oil Inc.".

Acquisition of Nycan Energy Corp.

In April, 2003, APF Energy acquired all of the issued and outstanding common shares of Nycan for approximately $42.4 million of cash purchase consideration. The acquisition added production of approximately 1,265 boe/d, consisting of 5.7 mmcf/d of natural gas and 315 bbl/d of oil and NGLs.

Further information concerning Nycan is set out in the prospectus of the Trust dated March 19, 2003 under the heading "Information Concerning Nycan". Information under the sub-headings "Principal Producing Properties - Major Properties and Minor Properties", "Summary of Principal Properties of Nycan", "Production History", "Estimated Production", "Producing Wells" and "Undrilled Acreage" is incorporated herein by reference.

Effect of the Significant Acquisitions on the Trust/APF Energy

The impact of the significant acquisitions as described above on the operating results and financial position of the Trust is described in detail in the prospectus of the Trust dated January 27, 2004 under the heading "Effect of Significant Acquisitions on the Trust/APF Energy" which information is incorporated by reference herein.

Other Acquisitions During 2003

Acquisition of CanScot Resources Ltd.

In September, 2003, APF Energy acquired all of the common shares of CanScot for approximately $42.1 million. The consideration was paid by the issue of 1,342,004 Trust Units and the payment of cash of $19.7 million. APF Energy also assumed $6.1 million of debt. The transaction comprised a focused group of high working interest, long-life conventional and coalbed methane properties in Alberta and Wyoming and added approximately 800 boe/d of production, 81% of which is natural gas. Of this production, approximately 80% was conventional and 20% was Wyoming coalbed methane production. Approximately 45,800 net acres of undeveloped land were also added as a result of the acquisition. A large portion of this land is considered to have potential for coalbed methane production.

CanScot carried on its operations in the United States through its wholly-owned subsidiary, Tika, a Wyoming company. Tika is now a wholly-owned United States subsidiary of APF Energy following the amalgamation of APF Energy and CanScot on October 1, 2003.

Mr. Donald Engle, Chairman of the Board of APF Energy, was also a Director and shareholder of CanScot.

Acquisition of Swan Hill Assets

On June 17, 2003, APF Energy announced that it had entered into an agreement to acquire a 17% interest in the Swan Hills Unit No. 1 and certain non-unit rights for $91.75 million in cash. Rights of first refusal ("ROFRS") encumbered the assets and ultimately ROFRS encumbering approximately 85% of the assets were exercised. As a result, the acquisition, which closed July 30, 2003 was reduced to $15.9 million. The acquisition added production of approximately 380 boe/d, of which 89% is light oil.

Acquisition of Countess Assets

On May 29, 2003, APF Energy completed the acquisition of gas production and deep rights in its core area of Countess, located in southeast Alberta for $7.0 million.

The Countess assets are an overlay on existing APF Energy lands in the northern part of the field and at the time of acquisition produced 1.2 mmcf/d, principally from the Mannville and basal Colorado formations. APF Energy's existing daily production at Countess was approximately 9.3 mmcf from the shallower Medicine Hat and Milk River zones. The acquisition of these deeper rights (average 73% working interest, most of which is operated) provides APF Energy with an opportunity to add to its inventory of development drilling prospects.

Internalization of Management

On January 3, 2003, the Trust indirectly acquired all the shares of APF Management Inc. ("APF Management"), the former manager of the Trust, and its subsidiaries, in accordance with a share purchase agreement among the Trust, 1014621 Alberta Ltd., a corporation owned by the Trust and newly formed to act as purchaser, APF Management and all of its shareholders. This effected the buyout of the management contracts with APF Management and the purchase of the rights to the 1% and 3.5% revenue streams and structuring fee entitlements owned by APF Management for $9.25 million, paid 25% in cash and 75% in Trust Units. Of the 661,850 Trust Units issued, 293,930 were originally held in escrow, 150,526 of which were releasable over a three-year period, and 143,404 being releasable over a four-year period On January 5, 2004, 86,026 Trust Units were released from escrow.

All of the major conditions, including regulatory approval, had been obtained by December 31, 2002. Accordingly, the transaction was accounted for in 2002.

The shares of APF Management were owned, directly or indirectly, as to approximately 70% by Mr. Martin Hislop and Mr. Steven Cloutier, both directors and respectively, the CEO, and President and COO of APF Energy, and Mr. Hislop's spouse, Claire Stephens. The remaining 30% of shares of APF Management were owned by members of Mr. Hislop's and his spouse's immediate families, who were not at the time and are not now directors or officers of APF Energy or APF Management.

APF Energy, APF Management and 1014621 Alberta Ltd. were amalgamated effective January 3, 2003.

APF Energy now provides management and administrative services to the Trust and its subsidiaries, similar to the services provided by APF Management prior to the Internalization Transaction.

RECENT DEVELOPMENTS

On February 4, 2004, the Trust closed a bought deal financing with a syndicate of underwriters led by Scotia Capital Inc. and issued 4.765 million Trust Units at $11.60 per Trust Unit for gross proceeds of $55.274 million.

On April 7, 2004, APF Energy announced that it has entered into an agreement dated April 6, 2004 pursuant to which it has agreed to make an offer (the "Offer") to acquire all of the shares of Great Northern Exploration Ltd. ("GNEL") for total consideration of approximately $283 million consisting of assumption of debt of approximately $56 million and payment for GNEL shares by either $5.05 in cash (subject to a maximum of $55.190 million in cash) or 0.414614 of a Trust Unit. The Offer is conditional on 66⅔% of the GNEL shares, on a fully diluted basis, being tendered and not withdrawn under the Offer. It is expected that the transaction will close in the first week of June, 2004.

STATEMENT OF RESERVES DATA

Information in this Statement of Reserves Data is prescribed by Section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Terms for which a meaning is given in NI 51-101 have the same meaning in this Statement.

The information provided with respect to the reserves data of APF Energy, APF Partnership and Tika is effective January 1, 2004 and was prepared March 2, 2004.

GLJ prepared the APF Report. APF Energy provided GLJ personnel with basic information which included land and accounting data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the APF Report is based, was obtained from public records, other operators, and from GLJ non-confidential files. The coalbed methane reserves of Tika in the United States were evaluated by McDaniel effective January 1, 2004 and were consolidated with the GLJ evaluated properties to generate corporate total forecasts.

A report on reserves data by GLJ and a report of management and directors on oil and gas disclosure are provided in Appendix "A" and Appendix "B" respectively, to this Annual Information Form.

Reserves Data

The following tables set forth certain information relating to the oil and natural gas reserves of APF Energy, APF Partnership and Tika, and the present value of the estimated future net revenue associated with such reserves, and is derived from the APF Report. **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									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)	Gross (mboe)	Net (mboe)
PROVED										
Developed Producing	12,215	10,730	1,012	943	66,108	54,804	821	585	25,066	21,393
Developed Non-Producing	825	771	668	633	4,859	3,805	84	54	2,386	2,093
Undeveloped	2,277	2,015	207	186	1,942	1,570	75	49	2,883	2,512
TOTAL PROVED	15,317	13,517	1,887	1,763	72,910	60,178	979	689	30,335	25,998
PROBABLE	4,728	4,144	1,277	1,164	27,110	22,082	173	122	10,696	9,110
TOTAL PROVED PLUS PROBABLE	20,044	17,661	3,164	2,926	100,020	82,260	1,153	811	41,030	35,108

Columns may not add due to rounding.

	NET PRESENT VALUE OF FUTURE NET REVENUE				
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
PROVED					
Developed Producing	463.3	363.9	303.9	263.5	234.2
Developed Non-Producing	46.4	28.1	20.5	16.4	13.8
Undeveloped	49.3	31.2	21.0	14.8	10.8
TOTAL PROVED	559.1	423.2	345.4	294.7	258.8
PROBABLE	184.1	120.6	88.4	68.8	55.6
TOTAL PROVED PLUS PROBABLE	743.2	543.8	433.8	363.5	314.4

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									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)	Gross (mboe)	Net (mboe)
PROVED										
Developed Producing	11,774	10,369	932	874	65,225	54,050	808	578	24,384	20,829
Developed Non-Producing	837	783	624	592	4,876	3,812	86	56	2,359	2,066
Undeveloped	2,269	2,077	201	181	2,016	1,612	75	50	2,880	2,576
TOTAL PROVED	14,880	13,229	1,756	1,646	72,118	59,473	968	684	29,623	25,471
PROBABLE	4,577	4,034	1,199	1,099	26,414	21,515	171	121	10,350	8,840
TOTAL PROVED PLUS PROBABLE	19,457	17,263	2,955	2,745	98,532	80,988	1,139	805	39,973	34,311

Columns may not add due to rounding.

	NET PRESENT VALUE OF FUTURE NET REVENUE				
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
PROVED					
Developed Producing	321.8	266.0	229.3	203.2	183.6
Developed Non-Producing	35.1	21.1	15.5	12.5	10.6
Undeveloped	31.7	19.3	12.2	8.0	5.2
TOTAL PROVED	388.6	306.4	257.0	223.7	199.4
PROBABLE	123.8	81.3	59.5	46.0	37.0
TOTAL PROVED PLUS PROBABLE	512.4	387.7	316.5	269.7	236.4

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 of APF Energy's 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.

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	1,099,628	178,434	312,147	23,603	26,384	559,061	–	559,061
Proved Plus Probable Reserves	1,427,638	246,214	404,377	50,667	28,216	743,164	–	743,164

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)	158,925
	Heavy Oil (including solution gas and other by-products)	18,212
	Natural Gas (including by-products but excluding solution gas from oil wells)	164,552
	Coalbed Methane	2,030
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	197,397
	Heavy Oil (including solution gas and other by-products)	27,416
	Natural Gas (including by-products but excluding solution gas from oil wells)	204,441
	Coalbed Methane	12,369

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	927,393	144,782	338,112	24,654	31,198	388,647	–	388,647
Proved Plus Probable Reserves	1,239,044	198,226	441,846	52,114	34,446	512,413	–	512,413

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)	106,715
	Heavy Oil (including solution gas and other by-products)	13,236
	Natural Gas (including by-products but excluding solution gas from oil wells)	133,479
	Coalbed Methane	1,343
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	132,651
	Heavy Oil (including solution gas and other by-products)	20,478
	Natural Gas (including by-products but excluding solution gas from oil wells)	158,929
	Coalbed Methane	4,560

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 $US/$Cdn	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 $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/bbl	Edmonton Propane $Cdn/bbl	Edmonton Butane $Cdn/bbl	Edmonton Pentanes Plus $Cdn/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 $US/mmbtu	Midwest Price@ Chicago Then Current $US/mmbtu	AECO-C Spot Then Current $Cdn/mmbtu	Alberta Plant Gate: Spot Then Current $/mmbtu	Alberta Plant Gate: ARP $/mmbtu	Alberta Plant Gate: Aggregator $/mmbtu	Alberta Plant Gate: Alliance $/mmbtu	Saskatchewan Plant Gate: SaskEnergy $/mmbtu	Saskatchewan Plant Gate: Spot $/mmbtu	Saskatchewan Plant Gate: Sumas Spot $US/mmbtu	British Columbia: CanWest Plant Gate $/mmbtu	British Columbia: Spot Plant Gate $/mmbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $Cdn/LT
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 weighted average one month price.

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

FORECAST PRICES AND COSTS

Year	OIL[1] 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)	Natural Gas[1] AECO Gas Price ($Cdn/mmbtu)	Edmonton Pentanes Plus (($Cdn/bbl)	Inflation Rates[1] (%/Year)	Exchange Rate[2] ($US/$Cdn)
Historical[3]								
2000	30.22	44.56	27.34	39.91	5.08	46.31	2.7	0.674
2001	25.97	39.40	16.94	31.56	6.21	42.48	2.6	0.645
2002	26.08	40.33	26.57	35.48	4.04	40.73	2.2	0.638
2003	30.96	43.51	26.01	37.26	6.66	44.01	2.8	0.721
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) Weighted average historical prices for the four most recent financial years.
(4) The price forecast is the GLJ standard price forecast effective January 1, 2004.

RECONCILIATION OF
COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE

(FORECAST PRICING)

The following table contains a reconciliation of APF's proved plus probable reserves for the most recently completed calendar year.

	Natural Gas (mmcf)			Light & Medium Oil (mbbl)			Heavy Oil (mbbl)			NGLs (mbbl)			Total (mboe)		
	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mbbl)	Net Probable (mbbl)	Proved Plus Probable (mbbl)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)
Reserves at December 31, 2002[3]	47,605	7,134	54,739	14,307	2,645	16,952	250	8	258	562	59	621	23,053	3,901	26,954
Extensions	1,066	877	1,943	212	115	327	–	–	–	3	3	5	393	264	656
Improved recovery	645	38	683	66	60	126	–	280	280	–	–	1	173	346	521
Technical revision	8	2,596	2,604	(369)	1,120	751	122	58	180	(38)	12	(26)	(284)	1,623	1,338
Discoveries	460	145	605	2	1	4	–	–	–	–	–	–	79	25	105
Acquisitions	19,632	10,792	30,424	2,111	537	2,648	1,621	754	2,374	253	47	300	7,257	3,136	10,393
Dispositions	(195)	(67)	(262)	(1,457)	(445)	(1,902)	–	–	–	–	–	–	(1,490)	(456)	(1,945)
Production	(9,748)	–	(9,748)	(1,643)	–	(1,643)	(347)	–	(347)	(95)	–	(95)	(3,710)	–	(3,710)
Reserves at December 31, 2003	59,473	21,515	80,988	13,229	4,034	17,263	1,646	1,099	2,745	684	121	805	25,471	8,840	34,311

Columns may not add due to rounding

Notes:

(1) Gross reserves for the purposes of this analysis are defined as total company interest reserves. Company interest reserves are defined as working interest reserves (before the deductions of royalties) plus royalty interest reserves.
(2) Net reserves for the purposes of this analysis are defined as net after royalty reserves.
(3) The evaluation as at December 31, 2002 was prepared using National Policy 2-B reserves definitions. Under those definitions, Probable Reserves were adjusted by a factor to account for the risk associated with their recovery. APF Energy previously applied a risk factor of 50% in reporting Probable Reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full Proved plus Probable Reserves are estimated to be

recoverable (Proved plus Probable Reserves are effectively a "best estimate"). The above reconciliation reflects current Probable Reserves versus previous risk adjusted (50%) Probable Reserves reported by APF Energy.

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

TOTAL PROVED RESERVES

CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	After Tax 2003 (M$)	Before Tax 2003 (M$)
Estimated Net Present Value at December 31, 2002	–	**375,861**
Oil and Gas Sales During the Period Net of Production Costs and Royalties[1]	(100,614)	(100,614)
Changes due to Prices and Royalties Related to Forecast Production[2]	(65,852)	(65,852)
Development Costs During the Period[3]	30,700	30,700
Changes in Forecast Development Costs[4]	(28,748)	(28,748)
Changes Resulting from Extensions and Improved Recovery[5]	24,963	24,963
Changes Resulting from Discoveries[5]	1,789	1,789
Changes Resulting from Acquisitions of Reserves[5]	86,992	86,992
Changes Resulting from Dispositions of Reserves[5]	(15,607)	(15,607)
Accretion of Discount[6]	37,586	37,586
Net Change in Income Taxes[7]	–	
Changes Resulting from Technical Reserves Revisions	(25,772)	(25,772)
All Other Changes[8]	54,564	24,113
Estimated Net Present Value as at December 31, 2003	–	**345,410**

Columns may not add due to rounding

__Notes:__

(1) Company actual before income taxes, excluding G&A.
(2) The impact of changes in prices and other economic factors on future net revenue.
(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
(4) The change in forecast development costs.
(5) End of period net present value of the related reserves.
(6) Estimated as 10% of the beginning of period net present value.
(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.
(8) Includes changes due to revised production profiles, estimated future abandonment and reclamation costs, development timing, operating costs, royalty rates, actual price received in 2003 versus forecast, etc.

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 $8.3 million in 2004 and $4.2 million in 2005.

Significant Factors or Uncertainties

For details of important economic factors or significant uncertainties that affect particular components of the Reserves Data, see "Management's Discussion And Analysis" and "Risk Factors – Business of APF Energy, APF Partnership and Tika".

Future Development Costs

The following table sets forth development costs deducted in the estimation of APF Energy's 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.

	Development Costs Deducted in Estimating Future Net Revenues													
	Development Costs – Undiscounted ($000)							Development Costs - 10% Discount Rate						
Reserves Category	2004	2005	2006	2007	2008	Thereafter	Total	2004	2005	2006	2007	2008	Thereafter	Total
Total Proved (Constant prices and costs)	10,352	4,524	3,559	626	788	3,754	23,603	9,870	3,921	2,804	448	513	1,503	19,061
Total Proved (Forecast prices and costs)	10,354	4,644	3,669	655	833	4,499	24,654	9,872	4,025	2,891	469	542	1,692	19,492
Total Proved plus Probable (Forecast prices and costs)	21,725	14,029	7,654	2,621	1,113	4,972	52,114	20,714	12,160	6,031	1,878	725	1,850	43,358

Other Oil and Gas Information

Oil and Gas Properties and Wells

Principal Producing Properties

At December 31, 2003, the properties in which APF Energy, APF Partnership and Tika held an interest included both unitized and non-unitized oil and natural gas production. All of the present value of the estimated future net revenue from the properties is located in the core areas as outlined in the table below:

Properties	Average Working Interest (1) %	Company Interest Reserves (2)(3) (mboe)	Estimated Net 2004 Production (6) (boe/d)	Reserve Life (3)(4) (Years)	Asset Value PV12 (3)(5) ($000)	(%)
CBM	36.6	1,475	173	10	4,247	1.4
Central Alberta	6.4	12,621	3,880	50	92,314	31.2
East Alberta & Heavy Oil	72.7	4,609	2,237	34	38,662	13.1
SE Saskatchewan	5.8	12,016	4,178	50	78,325	26.5
Southern Alberta	49.6	9,601	3,247	47	81,311	27.5
ARTC/GCA(7)		-	-		777	0.3
		40,322	13,715		295,636	

Notes:

(1) The percentage interest owned is based on the share of Proved Reserves plus Probable Reserves, as defined in NI 51-101, owned including working interest and overriding royalty interest.
(2) The share of recoverable reserves owned before the deduction of royalties.
(3) Based on Proved Reserves plus Probable Reserves outlined in the APF Report. See "Reserves Data" on page 11.
(4) Reserve life is the time remaining during which production is forecast to be economic.
(5) Discounted at 12% and based on the escalated price and cost forecast contained in the APF Report. ARTC is included, where applicable.
(6) The average production rate for 2004 as outlined in the APF Report.
(7) Alberta Gas Cost Allowance.

The following is a description, by area, of the principal producing oil and natural gas properties of APF Energy, APF Partnership and Tika. Unless otherwise specified, production estimates, gross and net acres and well count information are as at December 31, 2003. In this section, references to ownership by APF Energy includes the interests owned by APF Partnership and Tika. **All reserve data presented under this heading is based on the APF Report with an effective date of January 1, 2004. Reference should be made to the APF Report and the assumptions and other valuation criteria referred to in the "Statement of Reserves Data" section above.**

Core Properties

APF Energy's operations are divided into five business units: Southern Alberta; Central Alberta; East Alberta/Heavy Oil; Southeast Saskatchewan; and Coalbed Methane. Each business unit is comprised of technical and business professionals and support staff whose mandate is to increase the value of the assets under their management through a combination of development, exploration, optimization and acquisitions.

Southern Alberta

The Southern Alberta business unit is responsible for two general areas, most of which is operated: the Countess property, which APF Energy acquired as part of its initial public offering in 1996; and the assets acquired on the takeover of Nycan in April, 2003. This area is prospective for shallow gas in many horizons, including the Belly River, Milk River, Medicine Hat and Second White Specks formations. APF Energy also holds deeper rights on a number of its properties. Fourth quarter production in the Southern Alberta business unit was comprised of 15 mmcf/d of gas and 440 bbl/d of oil and NGLs. Drilling at Countess was extensive in 2003, with development initiatives replacing 100% of production on a proved plus probable basis. In total, APF Energy drilled 38 (28.2 net) gas wells, predominantly in the Milk River and Medicine Hat zones. The corporate acquisition of Nycan brought a large suite of contiguous multi-zone assets located southwest of the Countess field. During 2003, APF Energy participated in seven (1.7 net) wells on the Nycan lands. The 2004 budget contemplates total capital expenditures in the Southern Alberta business unit of $8 million, with 54 gross wells targeting a variety of shallow and deeper horizons.

East Alberta and Heavy Oil

The Hawk acquisition in February, 2003, provided APF Energy with a new heavy oil platform along the Alberta/Saskatchewan border. During the year, APF Energy drilled seven wells into a new pool at South Epping, which is now being considered for waterflood. Total production from this business unit averaged 2,147 boe/d during the fourth quarter of 2003, with heavy oil accounting for 1,300 bbl/d, or 10% of the total APF Energy portfolio. With high oil prices and a reasonable differential from light quality crude, APF Energy views its heavy oil assets as providing solid cashflow with upside potential. Total capital expenditures for the East Alberta/Heavy Oil business unit are expected to amount to $1.4 million in 2004, covering the drilling of five wells.

Central Alberta

Central Alberta has been an active area for APF Energy, as acquisitions and development initiatives pushed fourth quarter average production to 3,700 boe/d, comprised of 14 mmcf of gas and 1,370 bbl of oil and NGLs. With tremendous multi-zone potential, this area will continue to play an important role in APF Energy's development and optimization strategy. Total capital expenditures in 2003 amounted to $8.6 million, as the company participated in 48 (9.8 net) wells in areas such as Paddle River, Leaman, Pembina and Redwater. For 2004, the APF Energy budget contemplates $9.2 million of capital to be spent on seismic, land acquisition and the drilling of 25 gross wells.

Southeast Saskatchewan

APF Energy's largest oil producing area is Southeast Saskatchewan, where light gravity crude is produced predominantly from the Frobisher, Midale and Alida formations. Since acquiring its initial interests in the area in 2001, APF Energy has been very effective in executing both corporate development initiatives as well as its drilling strategies. In particular, the use of 3D seismic to delineate opportunities in under-exploited pools has proven very successful. The 2003 capital expenditures of $11.1 million resulted in 16 gross (9.1 net) horizontal oil wells and one vertical stratigraphic test. At Queensdale, APF Energy drilled four (2.4 net) horizontal wells and replaced 260% of production. During the year, APF Energy acquired minor partner interests and one quarter section of land, offsetting APF Energy operated production. The acquisition set up five (4.8 net) horizontal locations which have been included in the 2004 drilling program. Fourth quarter 2003 production averaged 4,100 boe/d, of which 96% was oil. In addition to Queensdale, active production and development areas in this business unit include Tatagwa and Macoun. For 2004, a budget of $14.1 million has been allocated to the drilling of 20 gross wells.

United States Coalbed Methane

Powder River Basin

APF Energy is currently active in six CBM projects in the Powder River Basin. Three of these fields are currently developed and producing gas. The remaining three projects are in the initial stages of development. The average cost to drill, case and complete a well in this area is approximately $US75,000.

Hensley Draw

Thirty CBM wells have been drilled to date in this area, where APF Energy has an average 23% working interest. These wells are completed in the Cook coal, which averages 11 metres in thickness at a depth of approximately 152 metres. Due to water discharge limitations, only 23 wells are currently on production. Gross production peaked at approximately 3,400 mcf/d, during the first quarter of 2003 and has now declined to approximately 2,000 mcf/d. An additional ten development locations are planned for drilling this year.

Kane

Fourteen CBM wells were drilled in late 2003 and are currently on production. These wells have been dually completed in both the Upper and Lower Wyodak coals, which average 11 metres in thickness per coal, at a depth of approximately 122 metres. As a result of the close proximity of adjacent production, many of these wells began producing gas immediately with a limited period of de-watering. Gross production is currently at 1,400 mcf/d and continues to increase as the coals are de-watered. An additional 30 locations have been identified for development over the next 18 months. APF Energy's interests range from 16% to 25%.

K-Bar

Twenty CBM wells have been drilled and are on production. Ten of these wells were completed in the Big George coal, which averages 12 metres in thickness at a depth of approximately 185 metres. Gross gas production peaked at over 3,000 mcf/d during the second half of 2002 after twelve months of de-watering. Production volumes have slowly declined to current rates of approximately 2,000 mcf/d. APF Energy has an average 16% working interest in this area. The remaining ten wells were completed in the Wyodak coal, which averages eight metres in thickness at a depth of 244 metres. This lower coal is exhibiting increasing gas production as the coals continue to be de-watered.

North Carson

This area is slated for development in 2004. With an 18% to 25% interest, an initial pilot project of eight wells is anticipated to be drilled by the end of the third quarter. These wells are planned to be drilled for co-mingled production in the Cook and Canyon coal seams, which average 7.6 metres in thickness at a depth of approximately 168 metres. A second round of drilling is planned on the same locations for co-mingled production from the Wall and Pawnee coal seams. Over 60 additional locations have been identified for drilling within the next 24 months.

Big Bend

APF Energy has the largest interest at 70% and is manager of this significant CBM project. Within the last few months, two test wells have been drilled to confirm gas content, structure and coal thickness. Based upon these results, an additional six wells will be drilled by the end of the second quarter. The initial eight well pilot project should begin de-watering during the third quarter of 2004. A second phase of 18 wells is planned for late 2004. Full scale development anticipates over 90 CBM wells on this project by late 2005.

Coal Gulch

This project area is slated for an initial development of 16 wells in 2005. These wells will target the Big George coal, which is approximately 15 metres thick at a depth of close to 670 metres. Several pilot projects in the Big George coal, located to the east of this project area have demonstrated excellent results.

Alberta Coalbed Methane

Based on an independent analysis of the potential CBM targets within the Western Canadian sedimentary Basin, various prospective coal units have been identified and quantified. The greatest prospectivity occurs within the Upper Mannville, which is estimated to contain approximately 65% of the potential gas in place within the Alberta Plains. Several discrete areas have been targeted for land acquisition and subsequent evaluation. APF Energy has focused its attention on an area approximately 113 kilometres northwest of Edmonton where three CBM project areas have been assembled. No reserves have been assigned for APF Energy's Alberta CBM properties, as NI 51-101 requirements specify that reserves cannot be booked until commercial production levels are established.

Corbett Creek

Following the drilling, coring and testing of an initial exploratory well, four CBM wells and a water disposal well were drilled in late 2002 with water production commencing in the spring of 2003. Following nine months of de-watering an additional six wells were drilled and completed in early 2004 with production commencing in March. It is anticipated that by accelerating water production, the associated gas production will increase. Based on the calculated permeability of the coal it is estimated that de-watering will take a minimum of 12 months. Once commercial rates are achieved, full scale development is expected to commence. Each well costs approximately $600,000 to drill, case and complete. APF Energy has an average 42% interest in over 10,000 acres at Corbett Creek with the potential to drill approximately 68 CBM wells.

Doris

At Doris, APF Energy has assembled 22,400 gross acres of contiguous lands with interests between 35% and 50%. An initial exploratory test well was drilled in 2003 to evaluate the coals and encountered several conventional gas zones and was completed in those intervals and placed on production. A second well on this CBM prospect was also successful in finding conventional gas and was placed on production in early 2004. A third well has now been drilled and tested the Upper Mannville coals and has confirmed the potential for CBM, with an initial five well pilot project planned for late 2004. An existing CBM project is currently underway by another operator approximately three miles to the west where over 40 wells have been drilled, mostly in the last year. Extensive de-watering is in progress on that property, which APF Energy believes will assist in the regional de-pressuring of the coals.

Timeu

An initial exploratory test well was drilled in the first quarter of 2004 and cored the Upper Mannville coal section. Following a thorough review of the data, a decision will be made regarding the drilling of a five well pilot project. APF Energy has assembled over 5,700 acres of land on this project, and has a 100% working interest in the area.

Trochu-Rowley

APF Energy has several active projects underway in this area located northeast of Calgary where over 60 CBM wells have been drilled by several companies. In this region, CBM development targets the Horseshoe Canyon coals. These coals are relatively thin and developed in up to ten individual seams with a total aggregate thickness of six to ten metres. These coals are also very shallow at depths of approximately 250 metres. These wells cost approximately $250,000 to drill, case and complete. One attribute of these coals is that there is no initial water production. APF Energy is drilling, completing and immediately placing these CBM wells on production. Due to the extremely competitive nature of this development, the company has established several joint ventures in this area and hopes to expand its operations here over the next 12 months.

Facilities

The following table sets out major facilities in which APF Energy and APF Partnership had an interest at December 31, 2003.

Area Name	Major Facilities[1]
S.E. Saskatchewan	Various working interests in batteries
Countess, Alberta	42% interest in the Countess natural gas plant; 100% interest in the Countess-Leckie compressor and 4 booster compressors
Redwater, Alberta	Interests in natural gas facilities as follows:
	90% Radway compression
	50% Redwater 8-9 compression and dehydration
	50% Redwater 13-27 compression and dehydration
Pembina, Alberta	Interests in unit oil treating and water injection facilities as follows:
	1.26% North Pembina Cardium Unit
	7.35% Pembina Cardium Unit No. 12
	100% Pembina Cardium Unit No. 20
	5.15% Pembina Cardium Unit 9
	65.78% Champlin-Peruvian Cardium Unit
	Interests in natural gas processing facilities as follows:
	0.52% Pembalta No. 1
	0.66% Pembalta No. 2
	1.10% Pembalta No. 3
	2.66% Pembalta No. 4
	0.10% Pembalta No. 5
	1.21% Pembalta No. 7
	0.47% Pembalta No. 8

Area Name	Major Facilities[1]
Paddle River, Alberta	Interests in natural gas facilities as follows:
	11.91% Paddle River Gas Plant
	19.25% Paddle River Acid Gas Injection
	15.19% Paddle River Gas Gathering and Compression
	100.00% Greencourt Gas Gathering and Inlet Separator
	10.42% Thunder Lake Gas Plant
Swan Hills, Alberta	Interest in the Judy Creek Conservation Plant:
	1.002065% Processing Plants 1, 2, 3, 4, 5, and 7
	3.700613% the Swan Hills gas gathering system
	0.943225% the South Swan Hills gathering system
	0.02318% the Judy Creek gas gathering system
	1.485365% the Virginia Hills gas gathering system
	1.17717% interest in Freeman Lake Water Plan
	7.90740% interest in Judy Creek Ethane Extraction Plan
	15.0000% interest in Judy Creek ATCO Sales Pipeline

Note:

(1) "Major Facilities" includes only significant processing facilities and pipelines associated with the designated area.

Producing Wells

The number of wells on the principal Properties in which APF Energy and APF Partnership had an interest as at December 31, 2003 and which it considers capable of production are set out in the following table:

	Producing[1][6]				Shut-in[2]					
	Gas		Oil		Gas		Oil		Other[5]	
	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]
CBM	13	4	–	–	–	–	–	–	–	–
East Alberta & Heavy Oil	30	29	245	204	2	1	43	25	40	36
Central Alberta	138	84	503	54	55	16	57	6	13	13
SE Saskatchewan	–	–	1,488	265	–	–	23	12	18	15
Southern Alberta	803	435	67	43	45	26	11	9	2	2
TOTAL	984	552	2,303	566	102	43	134	52	73	66

Notes:

(1) Information derived from an internal report of APF Energy.
(2) "**Shut-in**" wells means wells which are not producing but which APF Energy considers to be capable of production.
(3) "**Gross**" wells means the number of wells on the Properties in which APF Energy has an interest.
(4) "**Net**" wells means the number of gross wells multiplied by the net working interest share of APF Energy therein.
(5) "**Other**" wells include injection wells, disposal wells and service wells.
(6) All wells that are assigned Proved Non-Producing Reserves are within economic distance of gathering systems, pipelines or other means of transportation.

Properties with No Attributed Reserves

The following table outlines APF Energy's undeveloped land holdings as at December 31, 2003.

	Acres	
	Gross	Net
Alberta	422,156	236,039
Manitoba	966	412
Saskatchewan	156,524	77,172
USA	20,696	7,812
Total	600,342	321,435

There are no material work commitments on the undeveloped land holdings through December 31, 2003. APF Energy expects that 36,022 net acres of its undeveloped land holdings may expire within one year.

Forward Contracts

At March 15, 2004, APF had the following derivative financial instruments in place:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Hedged Price
March 2004	Crude oil	Swap	3,000 bbls	US$30.76/bbl
March 2004	Natural gas	Swap	10,000 GJ	Cdn$7.19/GJ
March 2004	Natural gas	Physical	2,000 mmbtu	US$7.00/mmbtu
April to June 2004	Crude oil	Swap	2,500 bbls	US$30.78/bbl
April to June 2004	Natural gas	Swap	10,333 GJ	Cdn$5.76/GJ
April to June 2004	Natural gas	Swap	1,000 mmbtu	US$5.19/mmbtu
July to September 2004	Crude oil	Swap	2,167 bbls	US$29.58/bbl
July to September 2004	Natural gas	swap	10,000 GJ	Cdn$5.75/GJ
July to September 2004	Natural gas	Swap	1,000 mmbtu	US$5.19/mmbtu
October to December 2004	Crude oil	Swap	1,833 bbls	US$30.45/bbl
October to December 2004	Natural gas	Swap	3,333 GJ	Cdn$5.75/GJ
October to December 2004	Natural gas	Swap	333 mmbtu	US$5.19/mmbtu
January 2005	Crude oil	Swap	1,000 bbls	US$31.74/bbl

In addition to commodity hedging, APF Energy has also entered into foreign currency hedge contracts in order to mitigate currency risk. APF Energy has hedged US$20 million of revenue at a rate of Cdn$1.3317 or US$0.7509 for calendar 2004.

Marketing Arrangements

As at January 1, 2004, APF Energy's production was approximately 45% natural gas and 55% oil and NGL. Gas is predominantly sold on the spot market or into short-term contracts. The balance of gas production (approximately 25%) is sold to aggregators pursuant to long-term contracts. The forecasted prices are set forth above, under "Summary of Pricing and Inflation Rate Assumptions – Forecast Prices and Costs". During 2003, natural gas was sold at an average of $6.32 per mcf, after hedging. Oil and NGL were sold on a combination of short-term and spot contracts, which averaged $34.46 and $31.82 per bbl, respectively, after hedging.

Additional Information Concerning Abandonment and Reclamation Costs

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date by APF Energy for abandonment and reclamation activities. Costs to abandon and reclaim approximately 1,160 net wells totaling $31.2 million ($13.1 million discounted at 10%) are included in the estimate of future net revenue. Facility abandonment costs of $15.1 million ($2.2 million discounted at 10%) are not included in the estimate of future net revenue. Abandonment and reclamation costs included in the estimate of future net revenue for the next three years are $2.05 million in 2004, $1.49 million in 2005 and $1.57 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.

Costs Incurred

The following table summarizes costs incurred for the year ended December 31, 2003.

Costs	($000)
Property Acquisition Costs	
Proved Properties	160,772
Unproved Properties	2,310
Exploration Costs	
Seismic	1,070
Development Costs	
Drilling and Completions	28,065
Facilities	7,749
Other	494

Drilling History

The following table sets forth the drilling activity for APF Energy, APF Partnership and Tika for the year ended December 31, 2003.

	Development Wells		Exploration Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Oil	59.0	18.40	1.0	1.00
Natural Gas	73.0	37.24	7.0	2.96
Coalbed Methane	19.0	4.40	-	-
Dry Wells	-	-	-	-
Other(3)	4.0	0.30	1.0	0.50
TOTAL	155.0	60.34	9.0	4.46

Notes:

(1) "Gross" wells means the number of wells in which APF Energy, APF Partnership and Tika have an interest.
(2) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest of APF Energy, APF Partnership and Tika therein.
(3) "Other" wells include injection wells, disposal wells and service wells.

Production Estimates

The following table sets out the gross volume of APF Energy's production, estimated for the year ended December 31, 2004, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Statement of Reserves Data" using 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
Proved Producing	4,492	916	34,634	385	11,566
Total Proved	4,898	1,074	37,580	372	12,608
Proved plus Probable	5,343	1,200	40,713	386	13,714

Production History - Last Four Quarters

	2003 Three Months Ended (unaudited)			
	December 31	September 30	June 30	March 31
Avg. Daily production (pre-royalty)				
Light & Medium Crude Oil (bbl/d)	5,206	5,541	5,220	5,630
Heavy Oil (bbl/d)	1,293	1,190	1,086	715
NGLs (bbl/d)	474	400	291	264
Gas (mcf/d)	36,929	33,675	35,758	28,745
Combined (boe/d)	13,128	12,744	12,557	11,400
Avg net prices (after hedging)				
Light & Medium Crude Oil ($/bbl)	35.98	34.86	35.62	41.61
Heavy Oil ($bbl/d)	22.48	26.94	24.48	34.43
NGL ($/bbl)	31.81	29.93	32.09	38.74
Gas ($/mcf)	5.45	5.86	6.67	7.85
Combined ($/boe)	32.96	34.09	36.65	43.38
Royalties ($000)				
Light & Medium Crude Oil ($/bbl)	7.52	6.98	7.05	8.64
Heavy Oil ($bbl/d)	3.51	1.41	2.51	2.83
NGL ($/bbl)	9.84	10.18	8.57	8.33
Gas ($/mcf)	1.12	1.01	1.46	1.67
Combined ($/boe)	6.84	6.17	7.51	8.86
Operating Expenses ($000) (1)				
Light & Medium Crude Oil ($/bbl)	10.25	8.06	8.76	8.11
Heavy Oil ($/bbl)	11.53	10.66	8.97	11.39
Gas ($/mcf)	0.99	1.01	0.79	0.73
NGLs ($/bbl)	-	-	-	-
Combined ($/boe)	7.97	7.17	6.68	6.55
Netbacks ($000)				
Light & Medium Crude Oil ($/bbl)	18.21	19.82	19.81	24.86
Heavy Oil ($/bbl)	7.44	14.87	13.00	20.21
Gas ($/mcf)	3.34	3.84	4.42	5.45
NGLs ($/bbl)	21.97	19.75	23.52	30.41
Combined ($/boe)	18.15	20.75	22.46	27.97
Expenditures ($000)				
Property Acquisitions(2)	3,594	18,156	7,165	323
(Dispositions)	(6,953)	(2,069)	(262)	-
Development(3)	11,948	10,360	5,726	5,567

Notes:

(1) Operating expenses include all costs (exclusive of drilling costs, completion costs and equipping costs) to operate wells for the recovery of petroleum, freehold mineral, municipal and property taxes and surface lease rentals, but do not include general and administrative expenses or management fees.

(2) The expenditures listed are for asset acquisitions and do not include corporate acquisitions.

(3) Including expenditures on facilities.

The following table indicates APF Energy's average daily production from its important fields for the year ended December 31, 2003.

	Light and Medium Crude Oil	Heavy Oil	Gas	NGLs	boe
	(bbl/d)	(bbl/d)	(mcf/d)	(bbl/d)	(boe/d)
Total Alberta	**1,143**	**28**	**31,954**	**357**	**6,851**
Countess/Leckie	5	–	10,336	2	1,730
Paddle River/Leaman	14	–	3,553	130	736
Pembina	424	–	661	54	588
Redwater	–	–	4,900	–	817
Sakwatamau	136	–	1,291	36	387
Other	564	28	11,213	135	2,593
Total Saskatchewan	**4,245**	**1,045**	**1,590**	–	**5,555**
Epping/South Epping	–	621	74	–	633
Macoun	397	–	247	–	439
Queensdale	940	–	250	–	982
Tatagwa	854	–	–	–	854
Other	2,054	424	1,019	–	2,648
Other Properties	**11**	**–**	**255**	**1**	**57**
Total	5,399	1,073	33,799	358	12,463

Note:

(1) Production numbers reflect total production averaged over the course of the year. Total production numbers were averaged for the time in which APF Energy owned the properties, which in many key properties was shorter than the course of the year.

Production History -Total 2003

	Year Ended December 31		
	2003	2002	% Change
Crude oil (bbl)	2,362,089	1,937,007	22
Natural gas (mcf)	12,336,650	6,748,075	83
NGL (bbl)	130,635	52,482	149
Total (boe)	4,548,832	3,114,168	46
Production split			
Oil and NGLs	55%	64%	(14)
Natural Gas	45%	36%	25

Note:

(1) Production volumes for the year were 46% higher in 2003, compared to 2002, due primarily to the acquisitions of Hawk, Nycan and CanScot. Natural production declines were partially offset throughout the year by production increases from successful development drilling programs at Queensdale, Macoun and Tatagwa in southeast Saskatchewan and at Countess in southeast Alberta.

AMENDMENT OF CREDIT FACILITIES

APF Energy executed a credit agreement dated July 19, 2001 amended as of July 31, 2001, March 13, 2002, May 30, 2002, December 31, 2002, February 5, 2003 and September 26, 2003 with a syndicate of Canadian resident financial institutions. The total principal amount of advances available under the credit facility is $150 million, comprised of a committed 364 day revolving credit facility renewable at the discretion of the lenders, with the outstanding principal amount being convertible to a one year term loan at the option of APF Energy. Upon any such conversion, any unused portion of the facility will be cancelled. The credit facility is available by way of the following: (i) Canadian dollar loans in multiples of $250,000 bearing interest at the bank's prime rate plus the applicable margin from 0.125% to 1.625%; (ii) Bankers' Acceptances in a minimum aggregate amount of $1,000,000 and integral multiples of $100,000 thereafter with fees based on the applicable margin from 1.125% to 2.0%; (iii) U.S. dollar loans in minimum principal amounts of U.S. $500,000 and integral multiples of U.S. $100,000 thereafter at the U.S. base rate plus the applicable margin from 0.125% to 1.625%; (iv) LIBOR loans in minimum principal amounts of U.S. $500,000 and integral multiples of U.S. $100,000 thereafter at the LIBOR rate plus the applicable margin from 1.125% to 2.0%; and (v) Letters of Credit and Letters of Guarantee for a maximum term of 12 months in amounts not less than $500,000 with a fee from 1.125% to 2.0%. The "applicable margin" is based on a sliding scale tied to the debt to cash flow ratio of APF Energy. The availability of the facility is limited to the borrowing base as determined from time to time by the lenders. The credit facility is secured by a $300 million principal amount demand debenture containing a first fixed charge on the oil and natural gas properties of APF Energy as required by the lenders and a floating charge on all of the other property of APF Energy, together with a general assignment of book debts from APF Energy registered in all provinces where it carries on business. The credit facility is also secured by an unlimited guarantee from each of APF Partnership, its General Partner, the Trust and APF Acquisition Trust, together with a $300 million principal amount fixed and floating charge demand debenture and a general assignment of book debts from APF Partnership and its General Partner and a pledge of all of the limited partnership units of APF Partnership held by APF Acquisition Trust. As well, all amounts owing by APF Energy and APF Partnership to the Trust and APF Acquisition Trust (including the Royalty) have been subordinated and postponed to amounts owing under the credit facility.

DIRECTORS AND OFFICERS

The Trust has no directors or officers. The name, municipality of residence, position held and principal occupation of each director and officer of APF Energy at December 31, 2003 are as set forth below. Directors of APF Energy are elected annually for a term of one year.

Name and Municipality of Residence	Position with APF Energy	Principal Occupation
Donald Engle, P. Land(1)(2) Calgary, Alberta	Director since December 1, 2000 and Chairman of the Board	President of Sapphire Resources Ltd., an oil and gas consulting company and Director and Chief Operating Officer of Welton Energy Corporation, a junior oil and gas company
William Dickson(1) Calgary, Alberta	Director since June 3, 1997	Director of Dickson Resources Inc., an oil and gas company and Director of IMS Petroleum Ltd.
Daniel Mercier(1)(2) Okotoks, Alberta	Director since October 1, 1996	Operations Advisor, SOCO International plc, an international oil and natural gas exploration company and President of Asia Energy Ltd., a private oil and gas company
Robert MacDonald(1) Calgary, Alberta	Director since June 11, 2003	Independent Businessman
Martin Hislop, C.A. Calgary, Alberta	Director since December 8, 1995 and Chief Executive Officer	Chief Executive Officer of APF Energy
Steven Cloutier, B.A., LL.B.(2) Calgary, Alberta	Director since December 8, 1995, President, Chief Operating Officer, Secretary and Treasurer	President and Chief Operating Officer of APF Energy
Bonnie Nicol, P.Eng. Calgary, Alberta	Vice-President, Operations	Vice-President, Operations of APF Energy
R. Kenneth Pretty, P. Land Priddis, Alberta	Vice-President, Corporate Development and Land	Vice-President, Corporate Development and Land of APF Energy
Alan MacDonald, C.A. Calgary, Alberta	Vice-President, Finance	Vice-President, Finance of APF Energy

Name and Municipality of Residence	Position with APF Energy	Principal Occupation
John Ewing, P. Geo. Calgary, Alberta	Vice-President, GeoScience	Vice-President, GeoScience of APF Energy
Daniel Allan, P. Geo. Calgary, Alberta	Vice-President, CBM Division	Vice-President, CBM Division of APF Energy

Notes:

(1) Member of the Audit Committee and Reserves Committee.
(2) Member of the Compensation Committee.

Each of the above-named directors and officers has held the same principal occupation for the past five years except as described below.

Mr. Engle is a professional Landman and has been President of Sapphire Resources Ltd., a private oil and gas consulting company, since 1975. He has also been a Director and Chief Operating Officer of Welton Energy Corporation, a junior oil and gas company, since August, 2003. From 1996 to May, 2000, Mr. Engle was also President of Grey Wolf Exploration Inc., a publicly traded oil and gas company listed on the Toronto Stock Exchange. He was also on the Board of CanScot from 2001 to September, 2003.

Mr. Dickson is a consultant, and has provided oilfield operations advice to oil and natural gas service companies since 1989, upon retirement as Vice President, Production of Ultramar Oil and Gas Canada Ltd. During that time, he has also been a director of Dickson Resources Inc., an oil and natural gas company and of Arlyn Enterprises Ltd., a vendor of commercial and consumer lubrication oils. From November, 1995 to January, 1997, he was Vice-President of 3-D Reclamation Inc., a company carrying on the business of abandoning and related reclamation of oil and natural gas wells.

Mr. Mercier is an Operations Advisor for SOCO International plc ("SOCO"). From September, 1998 until February, 2004, he was Vice President, Operations for SOCO. Prior thereto, he was Chairman, Chief Executive Officer and a director of Territorial Resources, Inc., a Colorado company engaged in international oil and natural gas exploration which merged with SOCO on September 8, 1998. SOCO is a publicly traded United Kingdom corporation engaged in international oil and natural gas exploration and production.

Mr. Robert MacDonald is an independent businessman. He was Director, Commercial Banking, CIBC World Markets, a subsidiary of a Canadian Chartered Bank, from October, 1998 to May, 2003. From March, 1998 to October, 1998, he was Managing Director, Koch Capital, the merchant banking arm of a private, U.S. based energy company. From 1993 to March, 1998, Mr. MacDonald was Vice President, Oil & Gas Group, Canadian Imperial Bank of Commerce. Prior to that, he spent 17 years in other positions within the financial services industry.

Martin Hislop has had the same principal occupation with APF Energy and predecessor companies since September of 1994 and became an officer of APF Energy in December, 1995. From 1986 to July of 1994, Mr. Hislop was President and Chief Executive Officer of Lakewood Energy Inc. and its predecessor, Lakewood Capital Group Inc.

Steven Cloutier has had the same principal occupation with APF Energy and predecessor companies since September of 1994 and became an officer of APF Energy in December, 1995. From 1991 to October 1994, Mr. Cloutier was in private law practice.

Ms. Nicol joined APF Energy in January, 1998. From February, 1997 to January, 1998, she was Manager, Saskatchewan and Provost Business Unit with Northstar Energy Corporation. She was Senior Exploration Engineer with Northstar from August, 1995 to January, 1997. From 1993 to 1995, she was Senior Petroleum Engineer with Northridge Exploration Inc. and prior thereto was a petroleum engineer with Chevron Canada Resources Limited.

Mr. Pretty joined APF Energy in March, 2001. From June, 2000 to March, 2001, he was Vice-President, Land and Business Development with Hunt Oil Company of Canada, and from March, 1998 to June, 2000 was Vice-President of Land with Newport Petroleum Corporation until it was acquired by Hunt Oil Company of Canada. From April, 1996 to March, 1998 he was employed at Petro-Canada as a staff landman and prior thereto was a senior landman at Amerada Hess Canada and Norcen Energy Resources Ltd.

Mr. Alan MacDonald joined APF Energy in August, 2001. From April 1999 to June 2001, he was Vice-President, Finance with Due West Resources Inc., and from 1987 to 1999 was Vice-President, Finance with Starvest Capital Inc.

Mr. John Ewing joined APF Energy in January 2003. From the beginning of 2000 to December 2002, he was the President of a private resources and consulting firm and from 1996 to 2000 was Vice-President of Tethys Energy Inc.

Mr. Daniel Allan joined APF Energy on October 1, 2003. In 1997, he founded CanScot as President and Chief Executive Officer and he continued in that position until the acquisition of CanScot by APF Energy.

As at April 1, 2004, the directors and executive officers of APF Energy, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, 677,478 (approximately 1.71%) of the outstanding Trust Units (approximately 3.87% after the exercise of options and rights pursuant to the Trust's Trust Unit incentive plans). Information regarding beneficial ownership and control of Trust Units, not being within the knowledge of the Trust, has been provided by the directors and officers, respectively.

Conflicts of Interest

There may be situations in which the interests of directors and officers of APF Energy will conflict with those of the Unitholders. Directors and officers of APF Energy own oil and natural gas properties that do not form part of the properties in which the Trust has an interest. Directors and officers of APF Energy may also acquire interests in energy-related businesses on their own account and on behalf of persons other than the Trust. Directors and officers of APF Energy may manage and administer such additional properties and may enter into other types of energy-related management and advisory activities. Thus, directors and officers of APF Energy will carry on their full time activities on behalf of the Trust and, when acting on behalf of others, may at times act in contradiction to or in competition with the interests of the Unitholders.

In resolving such conflicts, decisions will be made on a basis consistent with the objectives and funds of each group of interested parties and the time limitations on investment of such funds, all consistent with the duty of such management to deal fairly and in good faith with each such group of persons. The Administrative Services Agreement contains provisions which require APF Energy to act honestly and in good faith in exercising its duties under the agreement.

All conflicts among officers and directors of APF Energy will be resolved in accordance with the provisions of applicable legislation.

Properties will not be acquired from officers or directors of APF Energy or other managers, or persons not at arm's length with such persons, at prices which are greater than fair market value, nor will properties be sold to such persons at prices which are less than fair market value in each case as established by an opinion of an independent financial advisor or independent engineering firm and approved by the independent members of the board of directors of APF Energy.

Circumstances may arise where members of the board of directors of APF Energy serve as directors or officers of corporations which are in competition to the interests of APF Energy and the Trust. No assurances can be given that opportunities identified by such board members will be provided to APF Energy and the Trust.

SELECT CONSOLIDATED FINANCIAL INFORMATION

Following is certain combined financial data for APF Energy and the Trust for the periods noted.

	Twelve Months Ended December 31 ($000 except for per Trust Unit amounts)		
	2003	2002	2001
Revenues (net of royalties)	132,984	75,314	56,561
Expenses	104,269	70,679	43,241
Future income taxes	(14,333)	(7,133)	(5,174)
Minority interest	-	403	349
Net income (loss) after unusual items	43,048	11,768	18,144
Per trust unit	1.32	0.55	1.44
Per trust unit (diluted)	1.21	0.55	1.44
Cash distributions	68,713	37,766	37,311
Total assets	484,287	297,627	198,176
Long-term debt	98,000	88,000	59,250

The following factors affected the comparability of the above data.

Significant acquisitions

- In April, 2001 APF Energy completed the corporate acquisition of Alliance Energy Inc. for $59.5 million.
- In May, 2002 APF Energy completed the corporate acquisition of Kinwest Resources Inc. and 987687 Alberta Ltd. for $58.8 million.
- In February, 2003 APF Energy completed the corporate acquisition of Hawk for $49.1 million
- In April, 2003 APF Energy completed the corporate acquisition of Nycan for $42.4 million.
- In September, 2003 APF Energy completed the corporate acquisition of CanScot for $42.1 million.

Changes in accounting policies

- Effective January 1, 2004 the Trust adopted CICA Handbook Section 3870 "Stock-Based Compensation". Prospective adoption of the standard resulted in a $1.2 million charge to income during 2003, with no amendment to prior periods required.

	Three Months Ended (unaudited)							
	2003 ($000 except for per Trust Unit amounts)				2002 ($000 except for per Trust Unit amounts)			
	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31
Revenues (net of royalties)	31.543	32,737	33,294	35,410	23,943	20,977	17,000	13,393
Expenses	34,171	25,205	24,138	20,756	24,559	18,816	14,647	12,656
Future income taxes	482	(3,873)	(11,980)	1,038	198	(3,410)	(2,169)	(1,752)
Minority interest	-	-	-	-	128	108	93	75
Net income (loss) after unusual items	(3,110)	11,405	21,137	13,616	(942)	5,463	4,429	2,414
Per trust unit	(0.09)	0.32	0.66	0.54	(0.04)	0.25	0.22	0.14
Per trust unit (diluted)	(0.09)	0.31	0.65	0.54	(0.04)	0.25	0.22	0.14
Cash distributions	17,821	18,910	18,916	13,066	10,246	10,021	9,510	7,990
Total assets	484,287	486,729	433,853	376,917	297,627	274,961	282,994	198,585
Debt	98,000	90,000	102,000	97,000	88,000	61,000	63,000	38,000

MANAGEMENT'S DISCUSSION OF VARIATION IN OPERATING RESULTS

Reference is made to the information under the heading "Management's Discussion and Analysis" in the Annual Report, which information is hereby incorporated by reference into this Annual Information Form.

COMPETITIVE MATTERS

The Trust's cash distributions are dependent on a number of factors, including the underlying commodity prices and production of oil and gas assets of APF Energy and APF Partnership. To a large extent, the price of the Trust Units is in turn reflective of the quantum of the Trust's cash distributions.

In order to replace and add production, APF Energy must be able to acquire oil and gas assets on favourable terms. Moreover, the Trust must be able, from time to time, to access the equity markets in order to provide APF Energy with the capital required to make acquisitions.

The acquisitions' market is extremely competitive, both with respect to corporate transactions as well as to asset purchases. In addition to competition from other income trusts, the Trust and APF Energy must compete with oil and gas companies for the same opportunities. These competitors may have different financial strength than the Trust or APF Energy which may put them in a superior position.

ENVIRONMENTAL MATTERS

APF Energy carries out its activities in compliance with all provincial and federal regulations.

APF Energy has an Environmental and Safety Committee comprised of the Chief Operating Officer, Vice President, Operations and Environmental, Health and Safety Co-ordinator. This Committee reports directly to APF Energy's Board of Directors, which reviews environmental matters related to APF Energy's business. APF Energy is a member of the Canadian Association of Petroleum Producers ("CAPP") and, as such, participates in CAPP's environmental stewardship programs.

At present, APF Energy meets or exceeds all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Since these requirements apply to all operators in the oil and natural gas industry, it is not anticipated that APF Energy's competitive position within the industry will be adversely affected. APF Energy's major production facilities are relatively new and the likelihood of major capital expenditures being required to meet future changes is reduced in the near term. APF Energy has internal procedures designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding with them.

INDUSTRY CONDITIONS

The natural resource industry is subject to extensive controls imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the natural resource industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing fuels, distance to market and the value of refined products. Oil exporters are entitled to export oil pursuant to short term orders obtained from the National Energy Board ("NEB"), without the necessity of a public hearing before the NEB, provided that the terms of export contracts do not exceed two years in the case of heavy crude oil and one year in the case of oil other than heavy crude oil.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices with purchasers, provided that export contracts continue to meet certain other criteria prescribed by the NEB and the government of Canada.

The governments of Alberta and Saskatchewan also regulate the volume of natural gas which may be removed from those Provinces for consumption elsewhere.

The North American Free Trade Agreement ("NAFTA")

On January 1, 1994, NAFTA became effective among the governments of Canada, the United States of America and Mexico. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States of America or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period), (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations, which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Royalties payable on production from Crown lands are determined by government regulation and are, in general terms, calculated as a varying percentage of the value of gross production of oil or natural gas within certain limits, and may depend in part on any of the average price of all oil and natural gas sold, during a month, well productivity, geographical location and field discovery date.

From time to time the governments of Canada, Alberta and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. These programs reduce the amount of Crown royalties otherwise payable.

Land Tenure

Crude oil and natural gas located in the western Provinces are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such Provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulations

The oil and natural gas industry is currently subject to environmental regulation pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and natural gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated in the *Environmental Protection and Enhancement Act* (the "EPEA"). The EPEA brings a wider range of activities within the scope of environmental regulation. Environmental standards and the penalties are generally stricter under the EPEA than under the environmental regulatory regime it replaced. Other provinces either have or are considering adopting similar regulation.

RISK FACTORS

The following are certain factors related to the business of the Trust.

Business of APF Energy, APF Partnership and Tika

Acquisition Risks

APF Energy recently completed the acquisitions of Hawk, Nycan and CanScot to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits. Achieving the benefits of these acquisitions will depend in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as APF Energy's ability to realize the anticipated growth opportunities and synergies from combining the businesses of Nycan, Hawk, CanScot and APF Energy. The integration of Nycan, Hawk, CanScot and Tika will require the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the disruption of ongoing business, customer and employee relationships that may adversely affect APF Energy's ability to achieve the anticipated benefits of the acquisitions.

Purchase of Royalty

The price paid for the purchase of the Royalty in the properties of APF Energy APF Partnership and Tika (which are collectively referred to as "APF Energy" in this section entitled "Risk Factors") is based on engineering and economic assessments made by independent petroleum engineers. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil, natural gas, NGLs and sulphur and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the properties, APF Energy and the Trust. In particular, changes in the prices of and markets for petroleum, natural gas, NGLs and sulphur from those anticipated at the time of making those assessments will affect the return on the value of the Trust Units. In addition, all of those assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than attributed to the properties of APF Energy.

Dependence on Operators of the Properties and on Management

Distributable income, as it relates to the Royalty, is directly dependent on the continuing production of petroleum substances from the properties of APF Energy, which, in turn, is dependent in part on the managerial ability of the operators of the properties and other working interest owners. Parties other than APF Energy may be the operators of the properties and APF Energy will only have a vote in respect of the management of the properties to the extent of its working interest therein. To the extent that an operator does not appropriately perform its obligations, or the majority of the working interest owners' interests differ from those of APF Energy, income from the properties and therefore the Royalty could be reduced.

As a result of its conversion to open-end status, the Trust may make acquisitions that represent significant new businesses for it, unrelated to the Royalty. Unitholders are entirely dependent on the management of APF Energy and the Trust in respect of all matters relating to the properties of APF Energy, the administration of the Royalty and to other investments of the Trust.

Environmental Concerns

The operation of oil and natural gas wells involves a number of natural hazards which may result in environmental damage, blow-outs or other unexpected or dangerous conditions resulting in damage to APF Energy's property or other properties that may be acquired and possible liability to third parties. The oil and natural gas industry is subject to extensive environmental regulation which provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. Although APF Energy has established a reclamation fund for the purpose of funding its future environmental and reclamation obligations, there can be no assurance that the reclamation fund will be sufficient to satisfy all such obligations.

APF Energy maintains liability insurance, where available, covering risks and in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent such insurance is available. Pursuant to agreements with third party operators, those operators are responsible for maintaining insurance coverage consistent with industry standards. APF Energy or other entities in which the Trust invests may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Further, liabilities may exceed the amount of insurance held. Costs incurred to repair such damage and pay such liabilities will reduce distributable income of the Trust and may make the continued operation of APF Energy's and such other entities' business uneconomic or impossible.

Coalbed Methane Operations

APF Energy has undertaken the development of coalbed methane ("CBM") reserves in Canada and the United States. CBM development in Canada is in the experimental stage and involves a long-term commitment of significant capital expenditures. CBM development will carry with it a number of risks, including uncertainty relating to the title to coalbed gas, the environmental movement against CBM development given the large number of wells required and issues relating to water disposal, and the risk that there will be a reduction in gas prices which could slow or stall CBM development. In addition, to the extent the applicable regulatory regime is designed to apply to conventional gas, there is uncertainty about its application to CBM development.

Because CBM is becoming increasingly competitive, there are no assurances that APF Energy will be able to continue to acquire assets and lands that are prospective for CBM, in both Alberta and Wyoming.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". APF Energy's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject APF Energy to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those proposed in Alberta's Bill 37 Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity of APF Energy's operations and facilities. The direct or indirect costs of these regulations may adversely affect APF Energy's business.

Price of Petroleum Substances

APF Energy's results of operations and financial condition, and therefore the amounts paid to the Trust pursuant to the Royalty, are dependent on the prices received for its oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of the Trust or its management. Any decline in oil or natural gas prices could have a material adverse effect on APF Energy's operations, financial condition, economically producible reserves and the opportunities for the development of its oil and natural gas reserves. Management of APF Energy intends to enter into hedging transactions at appropriate times to manage the risk associated with oil and natural gas price fluctuations. APF Energy may also manage the risk associated with changes in foreign exchange rates by entering into forward foreign exchange contracts. To the extent that APF Energy engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to credit risks associated with counter parties with which it contracts. Distributable income of the Trust will therefore be sensitive to prevailing oil and natural gas prices.

Borrowings of APF Energy

APF Energy currently has the right, subject to certain guidelines, to borrow funds for general corporate purposes including capital expenditures and to enable it to purchase oil and gas properties, and to pay the capital costs of properties and to secure such loans in priority to the Royalty. It is contemplated that additional credit facilities for new affiliates or subsidiaries of the Trust will be entered into from time to time. Amounts paid in respect of interest and principal on debt incurred in respect of the oil and gas properties of APF Energy and other assets or entities owned from time to time reduce distributable income of the Trust. APF Energy currently has a syndicated credit facility in the amount of $150 million, of which $98 million was drawn as of December 31, 2003. See "Amendment of Credit Facilities" on page 26. Borrowings, if any, variations in interest rates and scheduled principal repayments may affect the return on investment for Unitholders. Properties or other assets may be sold or realized on by the bankers of APF Energy, or otherwise disposed of if revenues are not sufficient to meet these obligations. In addition, the ability of APF Energy to borrow to make purchases or fund capital costs will depend on the availability of credit on terms acceptable to it. To the extent the Trust or APF Energy are required to use cash flow to finance capital expenditures or property acquisitions, the level of distributable income will be reduced.

Potential Conflicts of Interest

Circumstances may arise where members of the board of directors of APF Energy serve as directors or officers of corporations which are in competition to the interests of APF Energy or the Trust. No assurances can be given that opportunities identified by such board members will be provided to APF Energy or the Trust.

The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the Act. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the Act.

Depletion of Reserves on Properties

The Trust has certain unique attributes, which differentiate it from other traditional oil and natural gas companies. Distributable Income, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and NGLs reserves. APF Energy does not reinvest cash flow in the same manner as traditional oil and natural gas companies. Accordingly, absent capital injections, APF Energy's initial production levels and reserves will decline.

APF Energy's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on APF Energy's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, APF Energy's reserves and production will decline over time as reserves are produced.

There is strong competition relating to all aspects of the oil and natural gas industry. APF Energy actively competes for reserve acquisitions and skilled industry personnel with a substantial number of other oil and natural gas companies, many of which have significantly greater financial and other resources than APF Energy.

There can be no assurance that APF Energy will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives. The Royalty owned by the Trust will have no value when reserves from the properties of APF Energy can no longer be economically produced and, as a result, absent cash flow from other assets or entities owned by the Trust, Unitholders will have to obtain income and the return of capital invested out of cash flow derived from their investment in Trust Units during the period when reserves can be economically recovered.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, APF Energy's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired.

To the extent that APF Energy is required to use cash flow to finance capital expenditures or property acquisitions, the level of distributable income of the Trust will be reduced.

Nature of Trust Units

Securities such as the Trust Units share certain attributes common to both equity securities and debt instruments. The Trust Units do not represent a traditional investment in the oil and natural gas industry and should not be viewed by investors as shares in APF Energy or other entities in which the Trust invests. The Trust Units are created pursuant to the Trust Indenture and represent a fractional interest in the Trust. Unitholders are not afforded the same rights and protections as are typically afforded to shareholders of a corporation under corporate legislation, including rights of dissent or the ability to seek relief from a court on the grounds of oppression or unfairness.

The market price of the Trust Units is sensitive to a variety of market conditions including, but not limited to, commodity prices, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore APF Energy is not a trust company and, accordingly, it is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Income Tax Considerations and Government Regulation

There can be no assurance that income tax laws and government incentive programs relating to mutual fund trusts and the oil and natural gas industry, to the extent they impact on the status of the Trust and the resource allowance, will not be changed in a manner which will adversely affect the Unitholders.

Variations in Foreign Exchange Rates

The exchange rate for the Canadian dollar versus the U.S. dollar has increased significantly over the last 12 months, resulting in the receipt by the Trust of fewer Canadian dollars for its production, which may affect future distributions. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

Investment Eligibility

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit sharing plans ("Deferred Plans"). Where at the end of any month a Deferred Plan holds Trust Units that are not qualified investments, the Deferred Plan must, in respect of that month, pay a tax under Part XI.1 of the *Income Tax Act* (Canada) (the "Tax Act") equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Deferred Plan. In addition, where a trust governed by a registered retirement savings plan holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units while they are not qualified investments. Where a trust governed by a registered education savings plan holds Trust Units that are not qualified investments, the plan's registration may be revoked. There are also significant income tax consequences from the loss of mutual fund status.

The Trust Indenture contains provisions limiting ownership of Trust Units by non-residents of Canada, within the meaning of the Tax Act. These restrictions are described herein under "Securities of the Trust – Limitations on Non-Resident Ownership" and are intended as one measure for ensuring that the Trust continues to qualify as a mutual fund trust under the Tax Act. The Trust regularly monitors geographical address information obtained from its transfer agent to determine the level of non-resident ownership of Trust Units.

Return of Capital

Trust Units will have no value when reserves from APF Energy's properties can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment.

Delay in Cash Distributions

Although distributable income of the Trust is paid monthly, such distributable income will not necessarily reflect accrued distributable income in such month, but rather an estimate of the actual amounts received or receivable for the period and the amount of the "Trust Reserve", being the reserve maintained out of distributable income to fund the Deferred Purchase Obligation or for other investment purposes. In addition to the usual delays in payment by purchasers of oil and natural gas to the operator of the properties of APF Energy and from the operator to APF Energy, payments between any such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to gathering systems, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment of reserves for such expenses. The timing and amount of required capital expenditures will directly affect cash distributions to Unitholders.

Unitholder Limited Liability

Unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. The Trust Indenture provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely.

The operations of the Trust are conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Unitholders for claims against the Trust.

APPENDIX "A"
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

This is the form referred to in item 2 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.

To the board of directors of APF Energy Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2003. The reserves data consist of the following:

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

   (ii) the related estimated future net revenue; and

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

   (ii) the related estimated future net revenue.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 1, 2003, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net present Value of Future net Revenue (before income taxes, 10% discount rate) ($000)			
			Audited	Evaluated	Reviewed	Total
Gilbert Laustsen Jung Associates Ltd.	APF Energy Inc. Corporate Evaluation effective January 1, 2004 (prepared March 2, 2004)	Canada	$ –	$311,904	–	$311,904
McDaniel & Associates Consultants Ltd.	Tika Energy Inc. Evaluation effective December 31, 2003 (prepared March 17, 2004)	United States	–	–	4,560	4,560
			$ –	$311,904	4,560	$316,464

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

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

Gilbert Laustsen Jung Associates Ltd.

Executed as to our report referred to above at Calgary, Alberta, Canada, March 5, 2004

per: (signed) *Myron J. Hladyshevsky*, P.Eng.

APPENDIX "B"
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Terms to which a meaning is ascribed in NI 51-01 have the same meaning in this form.

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

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

(ii) the related estimated future net revenue; and

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

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data and reserves data of APF Partnership. The report of the independent qualified reserves evaluator is represented above.

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

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

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

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

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

(a) the content and filing with securities regulatory authorities of the Company's reserves data and other oil and gas information and that of APF Partnership;

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

(c) the content and filing of this report.

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

(signed) "Martin Hislop"
Chief Executive Officer, APF Energy Inc.

(signed) Bonnie Nicol
Vice-President, Operations, APF Energy Inc.

(signed) Donald Engle
Director, APF Energy Inc.

(signed) William Dickson
Director, APF Energy Inc.

Date: April 12, 2004

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OFFICE OF INTERNATIONAL CORPORATE FINANCE

APF ENERGY

NEWS RELEASE
April 22, 2004
Calgary, Alberta

TSX: AY.UN
AY.DB

APF Energy Trust Files its Annual Information Form

APF Energy Trust today filed with Canadian securities authorities its Annual Information Form for the year ended December 31, 2003, including disclosure and reports relating to reserves data and other oil and gas information pursuant to National Instrument 51-101. Copies of the filed documents may be obtained through www.sedar.com, APF's website www.apfenergy.com or by emailing APF at invest@apfenergy.com.

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.

For Further Information Please Contact

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