



March 4, 2005

TSX: SHN.UN

**NEWS RELEASE – FOR IMMEDIATE RELEASE
SHININGBANK ENERGY ANNOUNCES 2004 FINANCIAL RESULTS**

Shiningbank Energy Income Fund (the “Fund” or “Shiningbank”), today announced its audited financial results for the year ended December 31, 2004.

2004 HIGHLIGHTS

- Production volumes increased by 19% over 2003 to average 19,933 boe/d of which 72% was natural gas.
- Production increases were mainly due to the acquisition of Birchill Resources Limited in early 2004 and the subsequent development drilling.
- Revenues increased by 24% in 2004 to \$307.5 million, as a result of higher production volumes and commodity prices.
- Net earnings before income tax increased by 3% to \$52.6 million from \$51.2 million in 2003.
- Net earnings after income tax increased by 117% to \$138.8 million from \$64.0 million due to a \$74.8 million one-time recovery of future income taxes related to a corporate restructuring completed in the fourth quarter. This had no effect on cash flow or distributions.
- Cash flow before change in non-cash working capital increased 29% in 2004 to \$174.9 million, up from \$136.0 million in 2003.
- Fourth quarter distributions totaling \$37.4 million resulted in a payout ratio of 79% in the quarter and 84% for the year.
- The combination of strong commodity prices and level operating expenses, 1% higher than in 2003, resulted in record operating netbacks of \$25.96 per boe.
- The Fund’s balance sheet ended the year in very healthy condition with a debt to annual cash flow ratio of 1 to 1.
- **Investors’ pre-tax total return for 2004 amounted to 30%, comprised of a 15% cash-on-cash distribution yield and a 15% increase in unit price.**

Shiningbank Energy Income Fund - 2004 Financial and Operating Highlights

	Three months ended December 31,			Year ended December 31,		
	2004	2003 ¹	%	2004	2003 ¹	%
FINANCIAL						
(\$ thousands except per Trust Unit amounts)						
Oil and natural gas sales ²	\$ 82,453	\$ 58,474	41	\$ 307,514	\$ 247,207	24
Net earnings before income tax	13,974	6,092	129	52,607	51,232	3
Future income tax (recovery)	(74,064)	738	(10,136)	(86,199)	(12,722)	578
Net earnings after income tax	88,038	5,354	1,544	138,806	63,954	117
Cash flow before change in						
non-cash working capital	47,220	30,082	57	174,878	136,038	29
Distributions to unitholders	37,390	30,629	22	146,360	122,287	20
Distributions per Trust Unit	0.69	0.69	-	2.76	2.85	(3)
Long term debt	182,147	121,691	50	182,147	121,691	50
Unitholders' equity	515,944	364,215	42	515,944	364,215	42
OPERATIONS						
Daily Production						
Oil (bbl/d)	2,502	2,018	24	2,381	2,023	18
Natural gas (mmcf/d)	90.4	76.6	18	86.6	74.9	16
Natural gas liquids (bbl/d)	3,259	2,530	29	3,125	2,252	39
Oil equivalent (boe/d)	20,833	17,311	20	19,933	16,759	19
Average Prices (including hedging) ²						
Oil (\$/bbl)	\$ 42.61	\$ 33.62	27	\$ 43.14	\$ 37.95	14
Natural gas (\$/mcf)	\$ 7.20	\$ 6.32	14	\$ 7.06	\$ 7.00	1
Natural gas liquids (\$/bbl)	\$ 43.70	\$ 32.93	33	\$ 40.24	\$ 33.65	20
Oil equivalent (\$/boe)	\$ 43.23	\$ 36.71	18	\$ 42.14	\$ 40.42	4
UNIT TRADING						
Units traded (thousands)	12,715	9,073	40	44,001	37,262	18
Value traded (\$ thousands)	\$ 277,894	\$ 153,851	81	\$ 865,687	\$ 612,995	41
Unit price						
High	\$ 23.98	\$ 18.99		\$ 23.98	\$ 18.99	
Low	\$ 20.01	\$ 15.05		\$ 16.51	\$ 14.80	
Close	\$ 21.49	\$ 18.64		\$ 21.49	\$ 18.64	
Units outstanding (thousands)	54,141	44,343		54,141	44,343	

¹ 2003 figures restated as per note 3 to the consolidated financial statements.

² Oil & natural gas sales and average prices are stated before transportation costs.

The following discussion and analysis of the operating and financial results of Shiningbank is for the three months and year ended December 31, 2004. This information is provided as of March 1, 2005. The fourth quarter and year-end results have been compared with the corresponding periods in 2003. Certain comparative figures have been restated to reflect the accounting changes described in Note 3 to the consolidated financial statements. Average prices have been restated to be prior to transportation costs in order to be consistent with the 2004 presentation. This discussion and analysis should be read in conjunction with the Fund's audited consolidated financial statements for the years ended December 31, 2004 and 2003, together with the accompanying notes included herein. Additional information about the Fund is available on SEDAR at www.sedar.com.

Barrel of oil equivalent (boe) volumes are reported at 6:1 with 6 mcf = 1 bbl. All figures are in Canadian dollars unless otherwise noted.

Results of Operations

PRODUCTION VOLUMES

Daily Production Volumes

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Oil (bbl/d)	2,502	2,018	24	2,381	2,023	18
Natural gas (mmcf/d)	90.4	76.6	18	86.6	74.9	16
Natural gas liquids (bbl/d)	3,259	2,530	29	3,125	2,252	39
Oil equivalent (boe/d)	20,833	17,311	20	19,933	16,759	19
Natural gas % of production	72%	74%	(2)	72%	74%	(2)

Fourth quarter daily average production grew 20% over fourth quarter 2003, and 19% year over year. Natural gas liquids (“NGL”) accounted for the majority of the volume increases as a result of the acquisition of NGL-rich properties, notably Ferrier, during the year. The volume growth in 2004 was primarily due to acquisitions, along with a successful development drilling program.

The most significant acquisitions were the first quarter 2004 purchases of Birchill Resources Limited (“Birchill”) for \$170.1 million and Good Ridge Explorations Ltd. (“Good Ridge”) for \$7.0 million. Both acquisitions closed in early March and, together, added approximately 19% to 2004 production. These acquisitions were partially offset by the natural declines of producing properties, which are estimated to average 14% per year. Production in 2005 is expected to average between 19,500 and 20,000 boe/d.

The Fund’s 2004 drilling program added approximately 2,000 boe/d to year-end production rates. Due to wet weather in the spring and summer of 2004 which restricted field access, the effect of the drilling program was not fully realized until late in the year, and will carry over to 2005. Production from these new wells will initially decline faster than the Fund’s average. The impact is expected to be a slight increase in the average decline rate in 2005, as well as a marginal reduction in the Fund’s reserve life index until the wells have stabilized at a level of long-term deliverability.

PRICING (INCLUDING HEDGING ACTIVITY)

Average Prices - After Hedging

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Average Prices						
Oil (\$/bbl)	\$ 42.61	\$ 33.62	27	\$ 43.14	\$ 37.95	14
Natural gas (\$/mcf)	\$ 7.20	\$ 6.32	14	\$ 7.06	\$ 7.00	1
Natural gas liquids (\$/bbl)	\$ 43.70	\$ 32.93	33	\$ 40.24	\$ 33.65	20
Oil equivalent (\$/boe)	\$ 43.23	\$ 36.71	18	\$ 42.14	\$ 40.42	4
Benchmark Prices						
WTI (US\$/bbl)	\$ 48.28	\$ 31.21	55	\$ 41.40	\$ 31.04	33
AECO natural gas (Cdn\$/mcf)	\$ 7.08	\$ 5.59	27	\$ 6.79	\$ 6.70	1

Natural Gas

Shiningbank’s realized natural gas prices averaged \$7.20/mcf for the fourth quarter, 14% higher than for the same period in 2003. For the full year, the average price was 1% higher than 2003 at \$7.06/mcf. Natural gas pricing remained relatively flat throughout 2004 despite significant increases in oil prices. Hedging decreased the realized gas price by \$0.11/mcf for the quarter and \$0.07/mcf for the year, which compares with a 2003 hedging gain of \$0.35/mcf for the quarter and \$0.11/mcf for the year.

Gas pricing fundamentals remain strong. The Fund expects prices to weaken late in first quarter 2005 with the end of winter, a normal seasonal effect. The Fund also expects that there will be significant market volatility in 2005 with benchmark prices averaging in the range of Cdn\$6.50 to \$7.50/mcf. Shiningbank does not control the prices

received for its production, but it does mitigate market risk through various methods including hedges and geographical diversity.

Oil and Natural Gas Liquids

Realized oil prices for the quarter were \$42.61/bbl, up 27% from fourth quarter 2003. Hedging reduced the realized price by \$8.36/bbl for the quarter compared with a hedging loss of \$1.50/bbl in fourth quarter 2003.

For full-year 2004, Shiningbank's average oil price rose 14% to \$43.14/bbl. Hedging reduced this realized price by \$5.46/bbl as compared to a \$1.33/bbl decline in 2003. The benchmark West Texas Intermediate ("WTI") price averaged 33% higher than in 2003, however strength in the Canadian dollar partially offset this increase. Oil prices are expected to remain high in US dollar terms, with many analysts calling for a US\$40.00/bbl average price for 2005. Futures prices at the time of writing were over US\$50.00/bbl.

NGL prices were also strong, reflecting high oil prices. The average NGL price in the fourth quarter 2004 was 33% higher than in fourth quarter 2003 at \$43.70/bbl, and 20% higher for the full year at an average \$40.24/bbl.

Hedging

Shiningbank maintains an active hedging program designed to reduce the variability of cash flow and stabilize distributions. Under the Fund's hedging policy, not more than one-half of production volumes of any commodity can be hedged at any one time. Gains and losses from hedging activities are typically recorded when they are realized and are included in oil and natural gas sales unless a particular hedge is considered ineffective. During 2004, the Fund hedged an average of 26% of total gas production (25% - 2003) and 39% of total oil production (37% - 2003). Currently, Shiningbank has the following hedging contracts in place:

Period	Commodity	Volume	Price
April 1, 2004 – March 31, 2005	Gas	5,000 GJ/d	\$5.91 /GJ
November 1, 2004 – March 31, 2005	Gas	5,000 GJ/d	\$7.50 /GJ floor \$11.00/GJ ceiling
April 1, 2005 – December 31, 2005	Gas	5,000 GJ/d	\$5.00 /GJ floor \$6.39/GJ ceiling
January 1, 2005 – June 30, 2005	Oil	500 bbl/d	US\$37.00/bbl floor US\$50.50/bbl ceiling
February 1, 2005 – December 31, 2005	Oil	500 bbl/d	US\$40.00/bbl floor US\$55.40/bbl ceiling
April 1, 2005 – October 31, 2005	Gas	5,000 GJ/d	\$6.70/GJ

REVENUES

(000s)	Three months ended December 31,				Year ended December 31,			
	2004	% of Revenue	2003	% of Revenue	2004	% of Revenue	2003	% of Revenue
Oil	\$ 11,731	14	\$ 6,520	11	\$ 42,352	14	\$ 29,000	12
Natural gas	60,850	74	42,116	72	226,040	74	188,454	76
Natural gas liquids	13,102	15	7,664	13	46,019	15	27,667	11
Other income (loss)	(398)	-	49	-	91	-	84	-
Gas hedging	(909)	(1)	2,402	4	(2,229)	(1)	2,980	1
Oil hedging	(1,923)	(2)	(277)	-	(4,759)	(2)	(978)	-
	\$ 82,453	100	\$ 58,474	100	\$ 307,514	100	\$ 247,207	100

The accompanying table demonstrates the net effect of price and volume variances on revenues.

SALES VARIANCE ANALYSIS (INCLUDING HEDGING ACTIVITY)

(000s)	Three months ended December 31,		Year ended December 31,	
	2004/2003		2004/2003	
Oil and natural gas liquids				
Volume increase	\$	3,705	\$	15,880
Price increase		5,298		12,043
Net increase	\$	9,003	\$	27,923
Natural gas				
Volume increase	\$	8,057	\$	30,388
Price increase		7,366		1,989
Net increase	\$	15,423	\$	32,377

ROYALTIES

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Total royalties, net (000s)	\$ 19,159	\$ 12,794	50	\$ 63,930	\$ 53,628	19
As a % of revenue	23.2%	21.9%	6	20.8%	21.7%	(4)
Per boe	\$ 10.00	\$ 8.03	25	\$ 8.76	\$ 8.77	-

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. The royalty rate was marginally lower in 2004 due to a one-time credit received in the third quarter of 2004 related to 2003 Crown royalties, offset in part by the high commodity price environment. The fourth quarter royalty rate was 6% higher due to the hedging loss experienced in 2004 as compared to a hedging gain in 2003. Hedging gains and losses affect revenue without a corresponding effect on royalties. The 2004 fourth quarter pre-hedging royalty rate was 22.4% which is comparable to the 2003 rate of 22.7% for the same period. The Fund expects that commodity prices in 2005 will be similar to those realized in 2004, resulting in little change to the 2005 royalty rate. The Alberta government provides a credit under the Alberta Royalty Credit program, which the Fund is eligible to access on a small portion of its properties. The Fund recorded the maximum credit of \$500,000 in both 2004 and 2003.

TRANSPORTATION COSTS

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Transportation costs (000s)	\$ 1,186	\$ 1,293	(8)	\$ 5,550	\$ 5,050	10
Per boe	\$ 0.62	\$ 0.81	(23)	\$ 0.76	\$ 0.83	(8)

Transportation costs decreased 23% on a boe basis from fourth quarter 2003. The decrease was the result of prior quarter adjustments flowing through the fourth quarter. The 8% year over year decrease was the result of lower pricing and termination of certain transportation service commitments. In 2005, transportation costs are expected to be flat on a boe basis with 2004.

OPERATING COSTS

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Operating costs (000s)	\$ 11,465	\$ 11,058	4	\$ 48,692	\$ 40,536	20
Per boe	\$ 5.98	\$ 6.94	(14)	\$ 6.67	\$ 6.63	1

Operating costs on a boe basis decreased 14% from fourth quarter 2003 and increased 1% year over year. Higher field and plant maintenance costs in most areas were offset by volume increases in some areas with lower operating costs. The Fund expects 2005 costs to average \$7.00/boe. While the Fund has gained efficiencies of scale in its operations on a per boe basis, operating costs will remain under pressure due to rising field costs, aging of the property portfolio and the likelihood of higher energy costs in 2005.

OPERATING NETBACKS

Natural Gas Wells

(\$/boe)	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Oil and natural gas sales	\$ 44.47	\$ 35.36	26	\$ 42.90	\$ 40.12	7
Hedging gain (loss)	(1.22)	1.50	(181)	(0.78)	0.42	(286)
Royalties	10.09	8.07	25	8.83	8.91	(1)
Transportation costs	0.65	0.87	(25)	0.80	0.89	(10)
Operating costs	5.59	6.50	(14)	6.29	6.25	1
Operating netback	\$ 26.92	\$ 21.42	26	\$ 26.20	\$ 24.49	7

Oil Wells

(\$/boe)	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Oil and natural gas sales	\$ 49.70	\$ 35.27	41	\$ 46.94	\$ 39.49	19
Hedging gain (loss)	(7.54)	(0.97)	677	(4.45)	(1.00)	345
Royalties	8.07	7.06	14	7.55	6.64	14
Operating costs	14.29	13.50	6	14.15	11.96	18
Operating netback	\$ 19.80	\$ 3.74	44	\$ 20.79	\$ 19.89	5

All Wells

(\$/boe)	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Oil and natural gas sales	\$ 44.71	\$ 35.35	26	\$ 43.10	\$ 40.09	8
Hedging gain (loss)	(1.48)	1.33	(211)	(0.96)	0.33	(391)
Other income (loss)	(0.21)	0.03	(800)	0.01	-	-
Royalties	10.00	8.03	25	8.76	8.77	-
Transportation costs	0.62	0.81	(23)	0.76	0.83	(8)
Operating costs	5.98	6.94	(14)	6.67	6.63	1
Operating netback	\$ 26.42	\$ 20.93	26	\$ 25.96	\$ 24.19	7

Total operating netback increased 26% quarter over quarter due mainly to higher commodity prices and lower transportation and operating costs. The year over year operating netback increased 7% due to higher commodity prices and lower transportation costs.

GENERAL AND ADMINISTRATIVE COSTS

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
General and administrative costs (000s)	\$ 1,686	\$ 1,432	18	\$ 6,681	\$ 4,649	44
Per boe	\$ 0.88	\$ 0.90	(2)	\$ 0.92	\$ 0.76	21
Per average Trust Unit	\$ 0.03	\$ 0.03	-	\$ 0.13	\$ 0.11	18

General and administrative costs per boe decreased 2% from fourth quarter 2003, and increased 21% year over year. The increases, including higher per average Trust Unit metrics, were due to higher activity levels resulting from acquisitions and increasing costs for corporate governance due to additional regulation. At year end, Shiningbank had 43 full-time employees and 24 full-time and part-time consultants at its head office. Field and production staff consisted of two production superintendents, 18 full-time employees and 38 contract operators. Costs of field and production staff are included in operating costs. General and administrative costs for 2005 are expected to trend upward to approximately \$1.25/boe as a result of further corporate governance and related administrative costs.

INTEREST ON LONG TERM DEBT

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Interest on long term debt (000s)	\$ 1,759	\$ 1,093	61	\$ 6,159	\$ 6,103	1
Per boe	\$ 0.92	\$ 0.69	33	\$ 0.84	\$ 1.00	(16)
Per average Trust Unit	\$ 0.03	\$ 0.02	50	\$ 0.12	\$ 0.15	(20)

Interest expense, which includes bank charges, increased 61% from fourth quarter 2003 due to higher debt levels resulting from the funding of capital expenditures. Year over year interest expense was relatively flat due to higher debt levels being offset by lower interest rates. Shiningbank is currently in compliance with all external debt covenants. Interest expense in 2005 is expected to be approximately \$1.25/boe due to higher projected debt levels and interest rates.

DEPLETION, DEPRECIATION AND ACCRETION

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Depletion, depreciation and accretion (000s)	\$ 32,035	\$ 22,865	40	\$ 118,547	\$ 78,853	50
Per boe	\$ 16.71	\$ 14.36	16	\$ 16.25	\$ 12.89	26

Depletion, depreciation and accretion rose 16% per boe for the fourth quarter and 26% year over year. These increases were primarily due to expansion of the asset base from acquisitions made during the first quarter and associated future development costs. The fourth quarter depletion calculation was based on December 31, 2004 reserve estimates.

The 2003 comparative figure has been restated and increased by \$3.8 million as a result of the adoption of the new asset retirement obligation standard. The accretion of discount on the asset retirement liability and additional depletion due to asset retirement costs are now included as part of this expense.

TRUST UNIT INCENTIVE COMPENSATION

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Trust unit incentive compensation (000s)	\$ 333	\$ 147	127	\$ 1,263	\$ 572	121
Per boe	\$ 0.17	\$ 0.09	89	\$ 0.17	\$ 0.09	89

During fourth quarter 2003, the Fund elected to prospectively adopt amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3870, “Stock-based Compensation and Other Stock-based Payments” for all rights issued on or after January 1, 2003. At that time, a total of \$572,000 was expensed for 2003, representing the fair value of rights issued and which vested in 2003.

During fourth quarter 2004, one new issue of rights was granted. Six new issues of rights, aggregating 580,000 in total (2003 – 525,000) were granted during the year. The fair value of rights issued was determined using a Black-Scholes model, and will be brought into income over the vesting period of the rights. Expenses in 2004 of \$1.3 million represented the fair value of rights issued during 2003 and 2004 and which vested in 2004. All of these costs are “non-cash” costs and are not deducted in calculating distributions to unitholders.

INTERNALIZATION OF MANAGEMENT CONTRACT

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Internalization of management contract (000s)	\$ 1,307	\$ 1,561	(16)	\$ 3,511	\$ 5,989	(41)
Per boe	\$ 0.68	\$ 0.98	(31)	\$ 0.48	\$ 0.98	(51)

Effective October 9, 2002, the Fund internalized its management by acquiring all of the shares of Shiningbank Energy Management Inc., the former Manager of the Fund. Prior to the acquisition, the Fund paid fees of 3.25% of net operating income, a fee of 1.5% on the purchase price of acquisitions and a quarterly scheduled dividend in accordance with the terms of a management agreement. The acquisition eliminated all future fees and dividends.

Of the total purchase price of \$20.6 million, \$11.0 million was deferred, representing Exchangeable Shares subject to escrow provisions which are being amortized into income over specific vesting periods through 2007. During 2004, \$2.7 million (2003 - \$5.4 million) was expensed, representing the amortization of these escrowed Exchangeable Shares. At December 31, 2004, \$1.9 million was left to be amortized (\$1.3 million in 2005, \$0.4 million in 2006 and \$0.2 million in 2007).

Total consideration for the internalization was reduced by \$1.8 million at the time of the transaction to provide for performance and retention bonuses to be paid to employees. During 2004, the remaining balance of this bonus pool, or \$817,250, was paid out in cash and included in internalization expenses. This compares with \$582,000 paid in 2003.

TAXES

	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Capital and large corporation taxes (000s)	\$ (451)	\$ 139	(424)	\$ 574	\$ 595	(4)
Future income tax (recovery) (000s)	\$ (74,064)	\$ 738	(10,136)	\$ (86,199)	\$ (12,722)	578
Per boe	\$ (38.88)	\$ 0.55	(7,169)	\$ (11.74)	\$ (1.98)	493

The Fund is obligated to pay provincial capital taxes and federal large corporations tax in its operating entities. Under the Fund's structure, payments are made between Shiningbank Energy Ltd. and the Fund. These payments provide the mechanism for transferring income to unitholders along with tax benefits and future tax liabilities. Current income taxes are not presently payable by the Fund or Shiningbank Energy Ltd.

In first quarter 2004, the Alberta government passed legislation to reduce the provincial corporate income tax rate to 11.5% from 12.5% effective April 1, 2004. Shiningbank's expected future income tax rate incorporating this rate reduction is approximately 38.49% compared with the current rate of approximately 38.62% applicable to the 2004 tax year.

During the fourth quarter, the Fund changed its organizational structure to take advantage of certain tax attributes of a partnership acquired in the Birchill acquisition. These changes eliminated future income taxes payable within the Fund on income earned from the Birchill assets by taking advantage of the tax flow-through structure of that partnership. As a result of the Fund's restructuring, a reduction in future income taxes was credited to income in the fourth quarter in accordance with Canadian generally accepted accounting principles ("GAAP"). The effect on earnings for the year was an additional \$78.4 million, or \$1.50 per Trust Unit (\$1.47 diluted). Net earnings were also affected through increased depletion charges arising from future income taxes being recorded in the cost of the assets at the time of the Birchill acquisition. This additional depletion reduced earnings by \$8.1 million, or \$0.15 per Trust Unit, basic and diluted. The costs of the restructuring were included in general and administrative costs in the fourth quarter.

NET EARNINGS

Shiningbank's fourth quarter earnings were \$88.0 million or \$1.62 per Trust Unit (\$1.60 diluted). Earnings in fourth quarter 2003, after restatement for the retroactive application of new accounting policies, were \$5.4 million or \$0.12 per Trust Unit, basic and diluted. For the year ended December 31, 2004 net earnings were \$138.8 million or \$2.66 per Trust Unit (\$2.61 diluted), compared with restated 2003 figures of \$64.0 million or \$1.54 per Trust Unit (\$1.51

diluted). Net earnings for the fourth quarter were increased by \$78.4 million or \$1.44 per Trust Unit (\$1.43 diluted) as a result of an internal restructuring which reduced future income taxes. See "Taxes".

DISTRIBUTIONS TO UNITHOLDERS

Distributions to unitholders (000s except per Trust Unit amounts)	Three months ended December 31,			Year ended December 31,		
	2004	2003	%	2004	2003	%
Cash flow before change in non-cash working capital	\$ 47,220	\$ 30,082	57	\$ 174,878	\$ 136,038	29
Capital expenditures	(13,323)	(6,865)	94	(56,339)	(22,931)	146
Asset retirement expenditures	(208)	(57)	265	(684)	(218)	214
Working capital adjustments	3,701	7,469	(50)	28,505	9,398	203
Distributions to unitholders	\$ 37,390	\$ 30,629	22	\$ 146,360	\$ 122,287	20
Distributions per Trust Unit	\$ 0.69	\$ 0.69	-	\$ 2.76	\$ 2.85	(3)
Trust Units outstanding	54,141	44,343	22	54,141	44,343	22

Distributions to unitholders for the quarter increased 22% over the same period in 2003 to \$37.4 million, while distributions per Trust Unit were consistent in both periods at \$0.69. For full-year 2004, distributions to unitholders increased 20% to \$146.4 million from \$122.3 million in 2003. The increases in distributions to unitholders for both periods in 2004 were due to higher production volumes, large gains in pricing for oil and NGL and strong gas prices. On a per Trust Unit basis, the effect of an increased number of Trust Units outstanding offset the increase in distributions to unitholders. Full-year distributions decreased 3% to \$2.76 in 2004 from \$2.85 in 2003 as a result of greater holdbacks to fund capital expenditures. The Fund paid out 84% of its cash flow in 2004 compared with 90% in 2003. Management expects that the current distribution level will continue through 2005 provided that commodity prices remain at or near 2004 levels.

2005 Cash Flow Sensitivities

The estimated sensitivity of cash flow to commodity price variables is shown in the table below.

	(000s)	Per Trust Unit
US \$1 per bbl	\$ 1,700	\$ 0.03
Cdn \$0.25 per mcf	\$ 5,900	\$ 0.11
US \$0.01 exchange	\$ 800	\$ 0.01
100 bbl/d	\$ 1,100	\$ 0.02
1 mmcf/d	\$ 1,700	\$ 0.03
1% prime rate	\$ 1,900	\$ 0.03

INCOME TAX INFORMATION

In 2004, 73.57% of cash distributions paid by the Fund were required to be included in the income of unitholders. The remaining 26.43% reduced each unitholder's adjusted cost base ("ACB") for income tax purposes. A summary of cash distributions paid in 2004 and the implications for Canadian taxpayers is shown below.

Record Date	Payment Date	Distribution ¹ (\$ per Trust Unit)	Taxable Income (\$ per Trust Unit)	ACB Reduction (\$ per Trust Unit)
December 31, 2003	January 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
January 31, 2004	February 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
February 29, 2004	March 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
March 31, 2004	April 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
April 30, 2004	May 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
May 31, 2004	June 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
June 30, 2004	July 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
July 31, 2004	August 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
August 31, 2004	September 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
September 30, 2004	October 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
October 31, 2004	November 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
November 30, 2004	December 15, 2004	\$ 0.23	\$ 0.1692	\$ 0.0608
Total		\$ 2.76	\$ 2.0304	\$ 0.7296

¹ Distributions for income tax purposes are based on cash received during 2004 rather than accrual-based income reported elsewhere in this report.

For US unitholders, 82.39% of distributions were taxable in 2004. Unitholders in both Canada and the US should consult tax advisors as to the proper treatment of Shiningbank distributions for income tax purposes.

ANNUAL FINANCIAL INFORMATION

(000s except per Trust Unit amounts)	2004	2003	2002
		Restated (note 3)	Restated (note 3)
Oil and natural gas sales	\$ 307,514	\$ 247,207	\$ 142,661
Net earnings (loss) before income tax	52,607	51,232	(1,859)
Per Trust Unit – basic	1.01	1.23	(0.06)
Per Trust Unit – diluted	0.99	1.21	(0.06)
Net earnings after income tax	138,806	63,954	12,598
Per Trust Unit – basic	2.66	1.54	0.40
Per Trust Unit – diluted	2.61	1.51	0.40
Total assets	826,797	614,149	507,824
Total long term debt	182,147	121,691	115,283
Property acquisitions	2,615	156,829	49,595
Corporate acquisitions	177,067	-	-
Capital expenditures	56,339	22,931	11,867
Cash flow before change in non-cash working capital	174,878	136,038	68,243
Per weighted average Trust Unit	3.35	3.27	2.15
Distributions to unitholders	146,360	122,287	69,607
Per Trust Unit	2.76	2.85	2.16
Payout ratio	84%	90%	102%
Trust Units outstanding	54,141	44,343	33,194
Weighted average	52,209	41,595	31,677
Dividends to former Manager	-	-	517

Acquisitions are a key driver of Shiningbank's growth. In 2003, the Fund completed a major acquisition of properties at Ferrier/O'Chiese. In 2004, the Fund completed a major corporate acquisition of Birchill and a much smaller corporate acquisition of Good Ridge. Such acquisitions add to production volumes, revenues, earnings and assets. Revenues and earnings are also greatly affected by commodity prices, particularly natural gas prices as 72% of the Fund's 2004 production was natural gas. With its high weighting to natural gas, the Fund's revenue and earnings results closely track changes in natural gas pricing.

In 2003, substantial production growth through acquisitions and a rebound in oil and gas prices boosted revenues and earnings compared with relatively weak natural gas prices in 2002 which resulted in lower revenues and earnings. In 2004, the same combination of acquisition-driven production growth and high commodity prices resulted in higher revenues and cash flow. Earnings increased as a percentage of revenue in 2004 as a result of the recovery of future income taxes related to the Fund's internal restructuring.

QUARTERLY FINANCIAL INFORMATION

(000s except per Trust Unit amounts)	March 31	June 30	September 30	December 31
2004				
Oil and natural gas sales	\$ 69,625	\$ 80,723	\$ 74,713	\$ 82,453
Net earnings before income tax	13,485	12,851	12,297	13,974
Per Trust Unit				
- basic	0.29	0.24	0.24	0.26
- diluted	0.28	0.24	0.23	0.25
Net earnings after income tax	18,796	16,072	15,900	88,038
Per Trust Unit				
- basic	0.40	0.30	0.30	1.62
- diluted	0.39	0.29	0.29	1.60
Cash flow before change in non-cash working capital	39,544	45,190	42,924	47,220
Per weighted average Trust Unit	0.84	0.84	0.80	0.87
Distributions to unitholders	34,767	36,977	37,226	37,390
Per Trust Unit	0.69	0.69	0.69	0.69
Payout ratio	88%	82%	87%	79%
2003				
Oil and natural gas sales	\$ 60,180	\$ 65,507	\$ 63,046	\$ 58,474
Net earnings before income tax	16,885	15,027	13,227	6,092
Per Trust Unit				
- basic	0.47	0.36	0.30	0.14
- diluted	0.47	0.35	0.29	0.14
Net earnings after income tax	19,499	23,583	15,517	5,354
Per Trust Unit				
- basic	0.55	0.56	0.35	0.12
- diluted	0.54	0.55	0.35	0.12
Cash flow before change in non-cash working capital	34,176	36,723	35,057	30,082
Per weighted average Trust Unit	0.96	0.87	0.79	0.68
Distributions to unitholders	30,886	30,330	30,442	30,629
Per Trust Unit	0.78	0.69	0.69	0.69
Payout ratio	90%	83%	87%	102%

As with Shiningbank's annual results, quarterly fluctuations are primarily the result of production increases due to acquisitions, the Fund's development drilling program and realized gas prices which can be extremely volatile. Volume increases from acquisitions occurred in second quarter 2003 through the acquisition of assets at Ferrier/O'Chiese and again, in second quarter 2004 with the acquisitions of Birchill and Good Ridge.

Natural gas prices remained strong and relatively consistent through the two years, apart from exceptionally strong prices in first quarter 2003 which led to higher distributions for that period. Oil prices increased substantially in late 2004, however, with oil playing a small role in Shiningbank's overall revenues, and with increased capital programs absorbing the extra cash flow, there was no change in distributions.

COSTS OF ACQUISITIONS AND DEVELOPMENT

During the first quarter, Shiningbank spent \$177.1 million on the acquisitions of Birchill and Good Ridge. These acquisitions added approximately 19% to Shiningbank's production volumes for 2004 with the majority of additions coming in the Ferrier area, adjacent to Shiningbank's existing property and using much of the same infrastructure.

A total of \$56.3 million was spent on drilling and new facilities during 2004, compared with \$22.9 million in 2003. Cash flow was used to fund \$27.8 million of these expenditures, with the balance being funded by debt. The increased expenditures funded a successful development drilling program concentrated in the Ferrier/O'Chiese area. Of the year's total, \$13.3 million was spent in the fourth quarter compared with \$6.9 million in fourth quarter 2003. A total of 96 wells (20.3 net) were drilled in 2004, 88 (18.5 net) of which were successful gas wells, four (0.9 net) were successful oil wells and four (0.9 net) were dry and abandoned. In addition, Shiningbank farmed-out an additional 30 wells for which no costs were incurred.

In 2005, the Fund plans to spend approximately \$50 million on drilling, new facilities and maintenance capital. This will be funded through a combination of cash flow and debt financing.

NET ASSET VALUE

(000s except per Trust Unit amounts)	Discount Factor	
	10%	12%
Present value of reserves ¹		
Proved	\$ 672,753	\$ 634,333
Probable	188,585	166,835
Undeveloped lands	27,800	27,800
Working capital deficiency	(10,015)	(10,015)
Total assets	879,123	818,953
Long term debt	(182,147)	(182,147)
Net asset value	\$ 696,976	\$ 636,806
Trust Units outstanding	54,141	54,141
Net asset value per Trust Unit at December 31, 2004	\$ 12.87	\$ 11.76

¹ The present value of reserves is calculated based on price forecasts and reserve estimates prepared by Sproule Associates Limited in their December 31, 2004 evaluations.

LIQUIDITY AND CAPITAL RESOURCES

Shiningbank's ability to grow depends on access to bank lines of credit supplemented by periodic equity infusions. Smaller acquisitions through the course of the year are funded by bank debt. Equity is issued to fund single large acquisitions, or to pay down debt acquired following a number of smaller acquisitions. When the proceeds of an equity issue are greater than acquisition costs, the excess is used to reduce bank debt.

Since the Fund's initial public offering in 1996, 11 public equity issues have been completed. Acquisitions have led to steady accretion in value to unitholders. This accretion is offset when equity is issued as existing unitholders are diluted by the issue of new units. However, as all new equity issues have been done in conjunction with an acquisition, over time, unitholders have not been diluted. This is apparent in the stability of the Net Asset Value (NAV) per unit of the Fund over time. At the inception of the Fund, the NAV was \$9.43 per unit, discounted at 10%. At the end of 2004, despite payment of over \$19 per unit in distributions over eight years, the NAV per unit is at a level of \$12.87, discounted at 10%, indicating that unitholders have not been diluted.

Long Term Debt

The Fund has a \$225 million revolving credit facility with a syndicate of four Canadian chartered banks of which \$182.1 million was drawn at December 31, 2004. The revolving period extends to April 27, 2005, at which time the facility reverts to a two-year term with principal payments, if necessary, commencing on July 28, 2005. The facility is secured by a \$300 million floating charge debenture on all assets of Shiningbank together with supporting debentures and guarantees from the Fund's operating subsidiaries and affiliates. Borrowings under the facility bear interest at an annual rate ranging from the banks' prime rate to the banks' prime rate plus 0.95%, depending on the total debt to cash flow ratio or, at Shiningbank's option, the bankers' acceptance rate plus a stamping fee.

Unitholders' Equity

On March 8, 2004, the Fund issued 8,800,000 new Trust Units at \$17.00 each for gross proceeds of \$149.6 million. In addition, a total of 997,204 Trust Units were issued during the year under the Trust Unit Rights Incentive Plan, under the Fund's Distribution Reinvestment Plan, and through the exercise of Exchangeable Shares.

When equity is raised, the intended use of proceeds is specified in the related prospectus. Each major equity issue has been undertaken to acquire properties or to reduce debt incurred from prior acquisitions. In all cases, the proceeds were used according to the purpose specified.

As of March 1, 2005, the Fund had 54,280,516 Trust Units, 263,482 non-escrowed Exchangeable Shares and 353,614 escrowed Exchangeable Shares outstanding. Exchangeable Shares held in escrow will be released over the next three years under the terms of two escrow agreements. Exchangeable Shares are not eligible for distributions until they are exchanged for Trust Units at the discretion of the holder. The exchange rate was initially one Trust Unit for each Exchangeable Share. The exchange rate increases with each distribution by an amount equal to the per unit distribution divided by the 10-day weighted average trading price of the Trust Units preceding the record date for that distribution. As of December 31, 2004, the exchange rate was 1 to 1.32647.

Future Growth

Shiningbank's growth is based on its ability to raise debt and equity capital in Canadian financial markets. The Fund examines acquisition opportunities and selects those it believes to be accretive for such parameters as cash flows, distributions, net asset value, production and reserves.

Acquisitions are typically made using the Fund's credit facilities. Periodically, new Trust Units are issued, and the proceeds are used to pay down debt accumulated from previous acquisitions.

If the Canadian equity or debt markets were unable to satisfy Shiningbank's funding needs, it would impair the Fund's ability to continue to replace production and maintain distributions. The Fund has lines of credit held by four Canadian chartered banks, which provide sufficient debt capital to satisfy the Fund's ability to complete all but the largest acquisitions. However, the Fund's governing documents restrict debt levels to 40% of the value of its properties, and debt service costs are not to exceed 30% of the projected annual cash flow.

Contractual Obligations

(000s)	Total	Payments Due by Period			
		Less than 1 Year	1 - 3 Years	4 - 5 Years	After 5 Years
Long term debt principal ¹	\$ 182,147	\$ -	\$ 182,147	\$ -	\$ -
Operating leases	8,071	826	3,003	3,173	1,069
Pipeline transportation	5,234	1,306	2,612	1,316	-
Total obligations	\$ 195,452	\$ 2,132	\$ 187,762	\$ 4,489	\$ 1,069

¹ The long term debt obligation assumes that the revolving credit line is not renewed in April 2005.

Shiningbank has on-going capital commitments in the ordinary course of business for development drilling, equipment and facilities. These are funded through a combination of cash flow, debt financing and periodic equity financing.

CRITICAL ACCOUNTING ESTIMATES

The Fund makes numerous accounting estimates in its financial statements in order to provide timely information to users. A critical accounting estimate is one that requires management to make assumptions about matters that are highly uncertain at the time the estimate is made and, if a different estimate was used, financial results would be materially different. The following estimates are considered critical:

Reserves

The Fund must estimate its reserves. Reserves are evaluated and reported on annually by independent petroleum reserve evaluators who use various subjective factors and assumptions, including forecasts of costs based on geological and engineering data, projected future rates of production, and timing and amounts of future development costs. Although reserves are estimated, management believes the estimates are reasonable based on information available at the time the estimates were prepared. Management, the Fund's internal engineers, and the Board's Environmental, Corporate Governance and Reserve Review Committee all review and approve the estimates reported by the independent reserve evaluators.

As new information becomes available, changes are made to the reserve estimates and future development cost estimates. Historically, the Fund has had no significant changes to these estimates, with the exception of adjusting reserves for acquisitions and divestitures and the results of new drilling. Future actual results could vary greatly from the estimates made, resulting in material changes to the depletion calculation and asset impairment test.

Asset Retirement Obligation

The Fund's estimated asset retirement obligation is based on estimated timing and costs to abandon and restore properties.

FINANCIAL REPORTING

During 2003 and 2004, there were numerous changes to financial reporting and regulatory requirements. The most important changes for Shiningbank are described below.

Asset Retirement Obligations

Effective January 1, 2004, Shiningbank adopted CICA handbook section 3110, “Asset Retirement Obligations.” The standard requires the recognition and measurement of liabilities related to legal obligations to retire property, plant and equipment upon acquisition of the liability. The initial liability must be measured at fair value and subsequently adjusted for the accretion of discount and changes in the fair value. The asset retirement cost is capitalized and depleted into earnings over time.

Hedging Relationships

Effective January 1, 2004, the Fund adopted Accounting Guideline 13, “Hedging Relationships” which establishes standards for the documentation and effectiveness of hedging relationships for the purposes of applying hedge accounting. The adoption of this standard had no effect on the Fund’s financial results.

Trust Unit Incentive Compensation

In September 2003, the CICA amended section 3870 of its handbook - “Stock-based Compensation and Other Stock-based Payments.” Effective January 1, 2004, companies are required to use the fair value method to measure all stock-based payments and recognize compensation expense in their financial statements. The Fund elected to adopt these amendments in fourth quarter 2003 for all rights issued on or after January 1, 2003.

Previously the Fund followed common practice in the sector and used the excess of the unit price over the exercise price at the date of the financial statement as a surrogate for fair value. If the Fund were to continue to use this method under the amended standard, the Fund could experience large fluctuations, even recoveries, in compensation expense over the next 10 years. Because of the highly volatile nature of distributions and unit trading prices, management believes amounts expensed and/or recovered under this calculation do not properly represent the benefit conveyed to rights holders during the vesting period, and could be confusing when reading the financial statements.

Management considered numerous methods of determining the fair value of rights granted and has chosen to use a Black-Scholes option-pricing model to determine fair value. The calculation of fair value requires management to make numerous assumptions, as outlined in note 7 to the financial statements. Readers are cautioned that the assumptions made are estimates of future events and actual results could differ materially from those estimated.

Supplemental Disclosure

Management believes that distributions to unitholders, cash flow and netbacks are useful supplemental measures. Distributions to unitholders should not be construed as an alternate to net income as determined by Canadian GAAP. All references to cash flow throughout this MD&A are based on cash flow before changes in non-cash working capital, which management uses to analyze operating performance and leverage. Cash flow as presented is not intended to represent operating cash flow or operating profits, 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. Operating netbacks, which are calculated as average unit sales price less royalties, transportation costs and operating costs, represent the cash margin for product sold, calculated on a boe basis. Distributions to unitholders, cash flow and netbacks as presented do not have any standardized meanings prescribed by Canadian GAAP and therefore may not be comparable with the calculations of similar measure for other entities.

Forward-looking statements

This MD&A contains forward-looking statements relating to future events. In some cases, forward-looking statements can be identified by such words as “may,” “expects” or similar expressions. These statements represent management’s best projections, but undue reliance should not be placed upon them as they are derived from numerous assumptions. These assumptions are subject to known and unknown risks and uncertainties, including the

business risks discussed in this MD&A and in the AIF, which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted.

Barrel of oil equivalent

Barrel of oil equivalent (boe) volumes are reported at 6:1 with 6 mcf = 1 bbl. The 6:1 boe conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

Consolidated Balance Sheets

December 31 (\$ thousands)	2004	2003
		Restated (note 3)
ASSETS		
Current assets		
Accounts receivable	\$ 50,712	\$ 31,587
Prepaid expenses	4,471	2,630
	55,183	34,217
Fixed assets (note 4)		
Petroleum and natural gas properties and equipment	1,133,426	826,352
Accumulated depletion and depreciation	(364,814)	(248,670)
	768,612	577,682
Other assets		
	3,002	2,250
	\$ 826,797	\$ 614,149
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	\$ 40,268	\$ 30,727
Trust Unit distributions payable	24,930	20,428
	65,198	51,155
Long term debt (note 5)		
	182,147	121,691
Future income taxes (note 6)		
	33,266	50,564
Asset retirement obligation (note 3)		
	30,242	26,524
Unitholders' equity		
Trust Units (note 7)	706,954	550,267
Exchangeable Shares (note 7)	7,019	5,267
Contributed surplus (note 7)	1,416	572
Accumulated earnings	308,517	169,711
Accumulated Trust Unit distributions	(507,962)	(361,602)
	515,944	364,215
	\$ 826,797	\$ 614,149

See accompanying notes to the consolidated financial statements

Consolidated Statements of Earnings and Unitholders' Equity

Year ended December 31 (\$ thousands, except per Trust Unit amounts)

	2004	2003
		Restated (note 3)
Revenues		
Oil and natural gas sales	\$ 307,514	\$ 247,207
Royalties	63,930	53,628
	243,584	193,579
Expenses		
Transportation	5,550	5,050
Operating	48,692	40,536
General and administrative	6,681	4,649
Interest on long term debt	6,159	6,103
Depletion, depreciation and accretion	118,547	78,853
Trust Unit incentive compensation (note 7)	1,263	572
Internalization of management contract (note 10)	3,511	5,989
	190,403	141,752
Earnings before taxes	53,181	51,827
Capital and large corporation taxes (note 6)	574	595
Future income tax recovery (note 6)	(86,199)	(12,722)
Net earnings	\$ 138,806	\$ 63,954
Unitholders' equity, beginning of year	364,215	264,887
Issue of Trust Units	156,687	158,297
Change in Exchangeable Shares, net (note 7)	1,752	(1,208)
Change in contributed surplus (note 7)	844	572
Distributions to Unitholders	(146,360)	(122,287)
Unitholders' equity, end of year	\$ 515,944	\$ 364,215
Net earnings per Trust Unit (note 7)		
Basic	\$ 2.66	\$ 1.54
Diluted	\$ 2.61	\$ 1.51

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

Years ended December 31 (\$ thousands)	2004	2003
		Restated (note 3)
Operating activities		
Net earnings	\$ 138,806	\$ 63,954
Items not requiring cash		
Depletion, depreciation and accretion	118,547	78,853
Internalization of management contract	2,693	5,381
Trust Unit incentive compensation	1,263	572
Gain on sale of other assets	(232)	-
Future income tax recovery	(86,199)	(12,722)
Cash flow before change in non-cash working capital	174,878	136,038
Asset retirement expenditures	(684)	(218)
Change in non-cash working capital (note 8)	(21,291)	1,514
	152,903	137,334
Financing activities		
Increase in long term debt	60,456	6,408
Distributions to Unitholders	(146,360)	(122,287)
Issue of Trust Units	155,327	151,708
	69,423	35,829
Change in non-cash working capital (note 8)	4,502	512
	73,925	36,341
Total cash provided	\$ 226,828	\$ 173,675
Investing activities		
Property acquisitions	\$ (2,615)	\$ (156,829)
Corporate acquisitions (note 4)	(177,067)	-
Capital expenditures	(56,339)	(22,931)
Long term investments	(23)	(211)
Proceeds on sale of fixed assets	3,496	5,770
Proceeds on sale of other assets	1,000	-
	(231,548)	(174,201)
Change in non-cash working capital (note 8)	4,720	526
Total cash used	\$ (226,828)	\$ (173,675)

See accompanying notes to the consolidated financial statements

Notes to the Consolidated Financial Statements

For the years ended December 31, 2004 and 2003

(\$ thousands, except Trust Units and per Trust Unit amounts)

1. ORGANIZATION

Shiningbank Energy Income Fund (“Shiningbank” or the “Fund”) is an unincorporated open-end investment trust formed under the laws of the Province of Alberta pursuant to a trust indenture dated May 16, 1996 and subsequently amended. Operations commenced on July 1, 1996. The beneficiaries of the Fund are the holders (the “Unitholders”) of trust units (the “Trust Units”).

On March 5, 2004, the Fund acquired all of the shares of Good Ridge Explorations Ltd. (“Good Ridge”) through its wholly owned indirect subsidiary Shiningbank Energy Ltd. (the “Corporation”). On March 8, 2004, the Corporation acquired all of the shares of Birchill Resources Limited (“Birchill”) which in turn held substantially all of its assets in a partnership. Also on March 8, 2004, the Corporation, Good Ridge and Birchill were amalgamated, continuing as Shiningbank Energy Ltd. The partnership, which was renamed Shiningbank Energy Partnership (“SEP”), remained in place and was held by the Corporation.

On December 31, 2004, the Corporation transferred substantially all of its interest in SEP to a newly formed limited partnership called Shiningbank Limited Partnership (“SLP”) and SEP was wound up. SLP is held by a newly created operating trust called Shiningbank Operating Trust (“SOT”), the sole beneficiary of which is the Fund. The Corporation is the general partner of SLP.

The trust indenture provides that 300,000,000 Trust Units may be issued. Each Trust Unit represents an equal fractional beneficial interest in any distributions from the Fund and in the net assets of the Fund on termination or winding up of the Fund. All Trust Units rank among themselves equally and rateably without discrimination, preference or priority. The trust indenture provides that Trust Units are redeemable at any time on demand by the Unitholders at amounts as determined by a market price formula. The total amount payable by the Fund in respect of all Trust Units tendered for redemption, however, may not exceed \$100,000 in any calendar month.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management using Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

Significant items subject to such estimates and assumptions include the amounts recorded for depletion and depreciation of the petroleum and natural gas properties, accretion of discount on asset retirement obligations, and asset retirement expenditures which are based on estimates of reserves and future costs and the amounts recorded for Trust Unit incentive compensation which are based on the estimated fair value of rights granted. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

(a) Principles of consolidation

These consolidated financial statements include the accounts of the Fund and its direct and indirect subsidiaries, including the Corporation, SLP, SOT, Shiningbank Holdings Corporation (“SHC”) and 1130243 Alberta Inc.

(b) Fixed assets

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized. Such costs include land acquisition, geological, geophysical and drilling costs for productive and non-productive wells and directly related overhead charges. Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs. Gains or losses upon disposition of such properties are not recognized unless the disposition would alter the depletion and depreciation rate by 20% or more.

The costs of fixed assets, plus a provision for future development costs of proved undeveloped reserves, are depleted and depreciated using the unit-of-production method based on estimated total proved reserves volumes, before royalties, as determined by independent engineers. Proved reserves are converted to a common unit of measure on the basis of their approximate relative energy content. Other miscellaneous assets are depreciated on a declining balance basis at 20% per annum.

Oil and gas assets are evaluated annually to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects, exceeds the carrying amount of the cost centre. When the carrying amount is in excess, and is therefore assessed as not recoverable, an impairment loss would be recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate (see note 4).

(c) Goodwill

Goodwill is recorded upon a corporate acquisition when the total purchase price exceeds the net identifiable assets and liabilities of the acquired company. The goodwill balance is not amortized but instead is assessed for impairment annually or more frequently, if necessary. Impairment is determined based on the fair value of the reporting entity compared to the carrying or net book value of the reporting entity. Any impairment will be charged to earnings in the period in which the fair value of the reporting entity is below the carrying value.

(d) Asset retirement obligation

Shiningbank recognizes the fair value of an Asset Retirement Obligation (“ARO”) in the period in which it is incurred when a reasonable estimation of the fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

Previously, Shiningbank recognized a provision for estimated future site restoration and abandonment costs calculated on the unit-of-production method over the remaining proved reserves. Actual site restoration and abandonment costs were charged against the liability as incurred.

(e) Income taxes

The Fund is a taxable trust under the Income Tax Act (Canada). Any taxable income is allocated to the Unitholders and therefore no provision for income taxes relating to the Fund is included in these financial statements.

The Fund’s corporate subsidiaries follow the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

The Fund’s corporate subsidiaries are taxable Canadian corporations and are liable for tax on income that they retain. The Corporation is also subject to capital taxes in jurisdictions where such taxes apply and these taxes are deducted from distributions to Unitholders.

(f) Financial instruments

The Corporation from time to time employs financial instruments to manage exposures related to interest rates and commodity prices. These instruments are not used for speculative trading purposes. The Fund formally documents all relationships between hedging instruments and hedged items and assesses, both at the hedge’s inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. Gains and losses on commodity price hedges are included in

revenues upon the sale of related production provided there is reasonable assurance that the hedge is and will continue to be effective.

Realized and unrealized gains and losses associated with hedging instruments that have been terminated or cease to be effective prior to maturity, are deferred on the balance sheet and recognized in income in the period in which the underlying hedged transaction is recognized.

For transactions that do not qualify for hedge accounting, the Fund applies the fair value method of accounting by recording an asset or liability on the consolidated balance sheet and recognizing changes in the fair value of the instruments in the current period statement of earnings.

(g) Trust Unit Rights Incentive Plan

The Fund accounts for the Trust Unit Rights Incentive Plan using the fair value based method. Under this method, compensation costs attributed to the Trust Unit rights are measured at fair value at the grant date and recognized over the vesting period, with a corresponding increase to contributed surplus. Consideration paid by employees and directors of the Corporation on the exercise of Trust Unit rights under this plan is recorded in Trust Units equity upon receipt, along with the amount of non-cash Trust Unit incentive compensation expense recognized in contributed surplus.

(h) Joint ventures

Substantially all of the Fund's petroleum and natural gas activities are conducted jointly with others and, accordingly, these financial statements reflect only the Fund's proportionate interest in such activities.

(i) Per Trust Unit amounts

Basic earnings per Trust Unit is computed by dividing net earnings by the weighted average number of Trust Units outstanding for the year. Diluted net earnings per Trust Unit amounts reflect the potential dilution that could occur if securities or other contracts to issue Trust Units were exercised or converted to Trust Units.

(j) Revenue recognition

Revenue from the sale of oil and natural gas is recognized when the product is delivered.

(k) Comparative figures

Comparative figures have been reclassified to conform to current year presentation.

3. CHANGE IN ACCOUNTING POLICIES

(a) Asset retirement obligation

Effective January 1, 2004 Shiningbank has adopted CICA handbook section 3110, “Asset Retirement Obligations.” The standard requires the recognition and measurement of liabilities related to legal obligations to retire property, plant and equipment upon acquisition of the liability. The initial liability must be measured at fair value and subsequently adjusted for the accretion of discount and changes in the fair value. The asset retirement cost is capitalized and depleted into earnings over time.

This change in accounting policy has been adopted retroactively with restatement of the prior period presented for comparative purposes. The effect of the adoption is as follows:

Balance sheet	December 31, 2003	December 31, 2002
Increase in fixed assets for asset retirement costs	\$ 12,531	\$ 13,521
Net increase in asset retirement obligation	15,329	15,560
Decrease in future income tax liability	(771)	(493)
Decrease in accumulated earnings	(2,028)	(1,546)

Statement of earnings	Year ended December 31, 2003
Accretion expense on asset retirement obligation	\$ 1,981
Increased depletion due to asset retirement costs	1,845
Eliminate prior provision for site restoration	(3,066)
Increase future income tax recovery	(277)
Net earnings impact	\$ 483
Basic net earnings per Trust Unit	\$ 0.01
Diluted net earnings per Trust Unit	\$ 0.01

The estimated asset retirement obligation is based upon the Fund's net ownership interest in each area, estimated costs to abandon and reclaim wells and facilities in the area, and the anticipated timing of such expenditures.

Undiscounted expenditures totalling \$37.6 million are expected to be made over the next 33 years. The Fund's credit adjusted risk free rate of 7% and an inflation rate of 2% were used to calculate the present value of the obligation.

The Fund's asset retirement obligation is as follows:

	Year ended December 31, 2004	Year ended December 31, 2003
Carrying amount, beginning of year	\$ 26,524	\$ 23,907
Liability incurred during the year, net of dispositions	2,212	854
Settlement of liability during the year	(684)	(218)
Accretion expense	2,190	1,981
Carrying amount, end of year	\$ 30,242	\$ 26,524

(b) Trust Unit incentive compensation

During 2003 the Fund elected to adopt the amendments to the CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." The section was adopted effective January 1, 2003 and Trust Unit incentive compensation expense of \$572,000 was recorded in 2003 for rights granted during 2003 and vesting within the year.

(c) Hedging relationships

Effective January 1, 2004, the Fund adopted Accounting Guideline 13, "Hedging Relationships" that establishes standards for the documentation and effectiveness of hedging relationships for the purposes of applying hedge accounting. The adoption of this standard had no effect on the Fund's financial results.

4. FIXED ASSETS

(a) Acquisition of Birchill Resources Limited

Effective January 1, 2004 the Corporation acquired all the outstanding shares of Birchill for \$170.1 million. The transaction closed on March 8, 2004. The acquisition was accounted for by the purchase method and the results of operations of Birchill are included in the accounts from the closing date. Birchill and the Corporation were subsequently amalgamated.

Cash consideration	\$ 169,639
Related fees and expenses	463
Cost of acquisition	\$ 170,102
Working capital deficiency	\$ (5,724)
Future income tax	(66,700)
Asset retirement obligation	(3,028)
Petroleum and natural gas properties and equipment	245,554
Total consideration	\$ 170,102

(b) Acquisition of Good Ridge Explorations Ltd.

Effective January 1, 2004 the Corporation acquired all the outstanding shares of Good Ridge for \$7.0 million. The transaction closed on March 5, 2004. The acquisition was accounted for by the purchase method and the results of operations of Good Ridge are included in the accounts from the closing date. Good Ridge and the Corporation were subsequently amalgamated.

Cash consideration	\$ 6,935
Related fees and expenses	30
Cost of acquisition	\$ 6,965
Working capital	\$ 578
Future income tax	(2,201)
Asset retirement obligation	(147)
Petroleum and natural gas properties and equipment	7,025
Goodwill	1,710
Total consideration	\$ 6,965

(c) Ceiling test

The Fund performed a ceiling test calculation at December 31, 2004 to assess the recoverable value of fixed assets. Future prices were obtained from third parties, adjusted for commodity differentials specific to the Fund, and then escalated based on factors in the Fund's year-end independent reserves evaluation. The following table summarizes the benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of future net revenues from proved reserves exceeded the carrying value of the Fund's fixed assets at December 31, 2004.

Year	Oil		Gas	
	WTI US\$/bbl	Edmonton Light C\$/bbl	AECO C\$/mmbtu	Alberta Reference C\$/mmbtu
2005	\$ 44.29	\$ 51.25	\$ 6.97	\$ 6.76
2006	41.60	48.03	6.66	6.45
2007	37.09	42.64	6.21	6.00
2008	33.46	38.31	5.73	5.55
2009	31.84	36.36	5.37	5.21
2010	32.32	36.91	5.47	5.31
2011	32.80	37.47	5.57	5.38
2012	33.30	38.03	5.67	5.48
2013	33.79	38.61	5.77	5.58
2014	34.30	39.19	5.87	5.68
2015	34.82	39.78	5.98	5.79
Thereafter	+ 1.5%/annum	+ 1.5%/annum	+ 1.5%/annum	+ 1.5%/annum

5. LONG TERM DEBT

The Corporation has a \$225 million revolving credit facility with a syndicate of four Canadian chartered banks of which \$182.1 million was drawn at December 31, 2004 (2003 - \$121.7 million). The revolving period extends to April 27, 2005. If the revolving facility is not renewed on that date, it will revert to a two year term with principal payments commencing on July 28, 2005. The facility is secured by a \$300 million floating charge debenture on all assets of the Corporation together with supporting debentures and guarantees from operating subsidiaries and affiliates. Borrowings under the facility bear interest at an annual rate ranging from the banks' prime rate to the banks' prime rate plus 0.95%, depending on the Fund's total debt to cash flow ratio, or, at Shiningbank's option, the bankers' acceptance rate plus a stamping fee.

6. INCOME TAXES

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Corporation's and SHC's earnings before income taxes. This difference results from the following items:

	2004	2003
Taxable loss of the Corporation and SHC	\$ (27,800)	\$ (17,400)
Combined federal and provincial tax rate	38.62%	40.60%
Computed income tax recovery	(10,700)	(7,100)
Increase (decrease) in income taxes resulting from:		
Non-deductible Crown charges	3,500	1,800
Other	2,901	(222)
Internalization of management contract	1,400	2,400
Resource allowance	(1,800)	(1,900)
Change in tax rate	(3,100)	(7,700)
Internal restructuring	(78,400)	-
Future income tax recovery	(86,199)	(12,722)
Capital and large corporation taxes	574	595
Income and capital taxes	\$ (85,625)	\$ (12,127)

The recovery of future income taxes, through the internal restructuring, resulted from the transfer of the partnership acquired in the Birchill acquisition from the Corporation to a new operating trust, the beneficiary of which is the Fund.

The components of the Corporation's and SHC's future income tax liability at December 31, are as follows:

	2004	2003
Future income taxes:		
Oil and natural gas properties	\$ 49,151	\$ 59,999
Asset retirement obligation	(9,084)	(4,636)
Non-capital losses	(4,383)	(3,935)
Other	(2,418)	(864)
	\$ 33,266	\$ 50,564

7. TRUST UNITS

(a) Authorized

300,000,000 Trust Units

(b) Issued

	2004		2003	
	Number	Amount	Number	Amount
Balance, beginning of year	44,343,415	\$ 550,267	33,193,937	\$ 391,970
Issued for cash	8,800,000	149,600	10,338,500	155,078
Less: Commissions and issue costs	-	(8,143)	-	(8,216)
Issued on exercise of rights	618,166	8,024	134,673	1,831
Issued for cash under Dividend Reinvestment Plan	296,538	5,846	179,488	3,016
Issued on conversion of Exchangeable Shares	82,500	941	496,817	6,588
Transfer from contributed surplus on exercise of rights	-	419	-	-
Balance, end of year	54,140,619	\$ 706,954	44,343,415	\$ 550,267

(c) Exchangeable Shares

On October 9, 2002, SHC issued 1,136,614 Exchangeable Shares in connection with the management internalization transaction. The Exchangeable Shares are exchangeable, at the option of the holder, into Trust Units for no additional consideration. As at December 31, 2004, 353,614 (2003 - 555,678) Exchangeable Shares were held in escrow to be released over periods up to October 2007 under the terms of two escrow agreements. The number of Trust Units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted by the distributions paid to Unitholders divided by the 10-day weighted average unit price preceding the record date. The Exchangeable Shares are not eligible for distributions.

	2004		2003	
	Number	Amount	Number	Amount
Balance, beginning of year	126,290	\$ 5,267	378,872	\$ 6,475
Released from escrow	202,064	-	202,064	-
Conversion of Exchangeable Shares	(64,872)	(941)	(454,646)	(6,589)
Amortization of deferred portion	-	2,693	-	5,381
Balance, end of year	263,482	\$ 7,019	126,290	\$ 5,267
Exchange ratio, end of year	1.32647		1.18417	
Trust Units issuable upon conversion of non-escrowed shares	349,501		149,549	
Trust Units issuable upon conversion of escrowed shares	469,058		658,016	
Total Trust Units issuable upon conversion of all shares	818,559		807,565	

(d) Trust Unit Rights Incentive Plan

Under Shiningbank's Trust Unit Rights Incentive Plan the initial exercise price of rights granted may not be less than the current market price of the Trust Units as of the date of grant and the maximum term of each right is not to exceed 10 years. The exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to Unitholders in any calendar quarter exceed 2.5% (10% annually) of the Fund's consolidated net book value of fixed assets. A total of 3,197,796 Trust Units have been reserved for issuance under the plan. At December 31, 2004, there were 1,396,901 (2003 - 1,460,067) rights outstanding, of which 395,234 (2003 - 583,401) were exercisable at a weighted average exercise price of \$13.34 (2003 - \$14.20). In January 2005, a further 717,500 Trust Unit rights were granted.

Rights	2004		2003	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Balance, beginning of year	1,460,067	\$ 13.93	1,059,000	\$ 15.00
Granted	580,000	\$ 18.75	525,000	\$ 15.24
Forfeited	(25,000)	\$ 16.44	-	\$ -
Exercised	(618,166)	\$ 12.98	(123,933)	\$ 13.44
Balance before reduction of exercise price	1,396,901	\$ 16.31	1,460,067	\$ 15.22
Reduction of exercise price		(1.57)		(1.29)
Balance, end of year	1,396,901	\$ 14.74	1,460,067	\$ 13.93

The following table summarizes information about Trust Unit rights outstanding and exercisable at December 31, 2004:

Range of Exercise Prices	Rights Outstanding			Rights Exercisable	
	Number Outstanding At 12/31/04	Weighted Average Remaining Contractual Life (Yrs)	Weighted Average Exercise Price	Number Exercisable At 12/31/04	Weighted Average Exercise Price
\$ 10.00 to \$ 12.99	481,667	7.8	\$ 12.08	65,000	\$ 11.96
\$ 13.00 to \$ 16.99	380,234	6.8	\$ 13.92	330,234	\$ 13.62
\$ 17.00 to \$ 21.50	535,000	9.1	\$ 17.71	-	\$ -
\$ 10.00 to \$ 21.50	1,396,901	8.0	\$ 14.74	395,234	\$ 13.34

Shiningbank recorded Trust Unit incentive compensation expense of \$1,263,000 for the year ended December 31, 2004 (2003 – \$572,000) for rights issued in 2003 and 2004, and vesting within the year.

During the year, \$419,000 (2003 - \$nil) of contributed surplus was transferred to Trust Unit equity in respect of rights exercised during the period.

The following table reconciles the movement in the contributed surplus balance:

Contributed surplus	2004	2003
Balance, beginning of year	\$ 572	\$ -
Trust Unit incentive compensation	1,263	572
Net benefit on rights exercised ¹	(419)	-
Balance, end of year	\$ 1,416	\$ 572

¹ Upon exercise, the net benefit is reflected as a reduction of contributed surplus and an increase to Unitholders' capital.

The fair value of the 580,000 rights issued during the year was estimated using a Black-Scholes option-pricing model with the following assumptions: risk-free interest rates ranging from 4.33 to 4.82% (2003 – 4.16 to 4.76%), volatility of 60%, life of 10 years, and a dividend yield rate of 10% representing the difference between the anticipated distribution and the anticipated drop in the strike price.

For rights issued in 2002, Shiningbank has elected to disclose the pro forma effect as if the amended accounting standard had been adopted January 1, 2002. For the years ended December 31, 2004 and 2003, Shiningbank's net income would have decreased by \$508,000 per year (\$0.01 per basic and diluted Trust Unit in 2003 and 2004) due to additional Trust Unit incentive compensation expense related to rights granted in 2002.

(e) Distribution Reinvestment Plan

The Distribution Reinvestment Plan ("DRIP") entitles eligible Unitholders to purchase additional Trust Units by re-investing their cash distributions or by making additional optional cash payments of up to a maximum of \$3,000 per quarter for the purchase of additional Trust Units. Trust Units are acquired on the open market at the prevailing market price or issued from treasury at the average market price over the last 10 days of trading. During 2004, 296,538 Trust Units were issued from treasury (2003 – 179,488) under the DRIP for proceeds of \$5.8 million (2003 - \$3.0 million).

(f) Per Trust Unit amounts

For the year ended December 31, 2004, the weighted average number of Trust Units and non-escrowed Exchangeable Shares outstanding was 52,208,852 (2003 - 41,594,854). In computing diluted net earnings per Trust Unit, the dilutive effect of unit rights and escrowed Exchangeable Shares, added 984,155 Trust Units (2003 – 772,760) to the weighted average number of Trust Units outstanding.

8. OTHER CASH FLOW DISCLOSURES

(a) Change in non-cash operating working capital

	2004	2003
Accounts receivable	\$ (24,271)	\$ (7,950)
Prepaid expenses	(1,841)	248
Accounts payable and accrued liabilities	4,821	9,216
	<u>\$ (21,291)</u>	<u>\$ 1,514</u>

(b) Change in non-cash financing working capital

	2004	2003
Distributions payable to Unitholders	\$ 4,502	\$ 512

(c) Change in non-cash investing working capital

	2004	2003
Accounts payable for capital accruals	\$ 4,720	\$ 526

(d) Cash payments

	2004	2003
Cash payments made for taxes	\$ 1,231	\$ 625
Cash payments made for interest	\$ 6,023	\$ 6,077

9. FINANCIAL INSTRUMENTS

As at December 31, 2004, there are no significant differences between the carrying amounts and the fair value of accounts receivable, accounts payable, accrued liabilities, Trust Unit distributions payable, and long-term debt. The Corporation is exposed to interest rate variance on the long term debt disclosed in the balance sheet. Gains and losses on commodity price hedges are included in revenues upon the sale of related production provided there is reasonable assurance that the hedge is and will continue to be effective.

Substantially all of the Fund's accounts receivable are due from customers in the oil and gas industry and are subject to the normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of the associated credit risk. Substantially all derivative financial instruments are entered into with Canadian chartered banks in order to reduce credit risk.

At December 31, 2004, Shiningbank held certain oil and natural gas hedge contracts, the terms of which are listed in the following table. The estimated market value at December 31, 2004, had the contracts been settled at that time, would have been a loss of \$103,484.

Period	Commodity	Volume	Price
April 1, 2004 – March 31, 2005	Gas	5,000 GJ/d	\$5.91 /GJ
November 1, 2004 – March 31, 2005	Gas	5,000 GJ/d	\$7.50 /GJ floor \$11.00/GJ ceiling
April 1, 2005 – December 31, 2005	Gas	5,000 GJ/d	\$5.00 /GJ floor \$6.39/GJ ceiling
January 1, 2005 – June 30, 2005	Oil	500 bbl/d	US\$37.00/bbl floor US\$50.50/bbl ceiling

Subsequent to December 31, 2004, Shiningbank entered into two additional hedge contracts.

Period	Commodity	Volume	Price
February 1, 2005 – December 31, 2005	Oil	500 bbl/d	US\$40.00/bbl floor US\$55.40/bbl ceiling
April 1, 2005 – October 31, 2005	Gas	5,000 GJ/d	\$6.70/GJ

10. INTERNALIZATION OF MANAGEMENT CONTRACT

Effective October 9, 2002, the Fund acquired all of the outstanding shares of Shiningbank Energy Management Inc., the former Manager of the Fund. Total consideration for the transaction consisted of a cash payment of \$2.91 million plus 1,136,614 Exchangeable Shares. Total consideration was reduced by \$1.8 million to provide for performance/retention bonuses to be paid to employees. During 2004, the remainder of this bonus pool, or \$817,250 (2003 - \$582,750) was paid out in cash and expensed.

Total consideration:

Cash	\$ 2,910
Exchangeable Shares issued	16,490
Costs associated with the transaction	1,195
Total purchase price	\$ 20,595

Prior to the acquisition, the Fund paid fees to the former Manager of 3.25% of net operating income, a fee of 1.5% on the purchase price of acquisitions and a quarterly scheduled dividend in accordance with the terms of the management agreement. The acquisition resulted in the elimination of all fees and dividends under the management contract.

Exchangeable Shares in the amount of \$10.0 million were originally subject to escrow provisions and are being deferred and amortized into income as internalization of management contract expense over the specific vesting periods through 2007. For the year ending December 31, 2004, \$2,693,400 (2003 - \$5,380,600) has been recorded as expense representing the amortization of these escrowed Exchangeable Shares.

Shiningbank Energy Income Fund is a conventional oil and gas royalty trust and its units are listed on The Toronto Stock Exchange under the symbol “SHN.UN”.

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