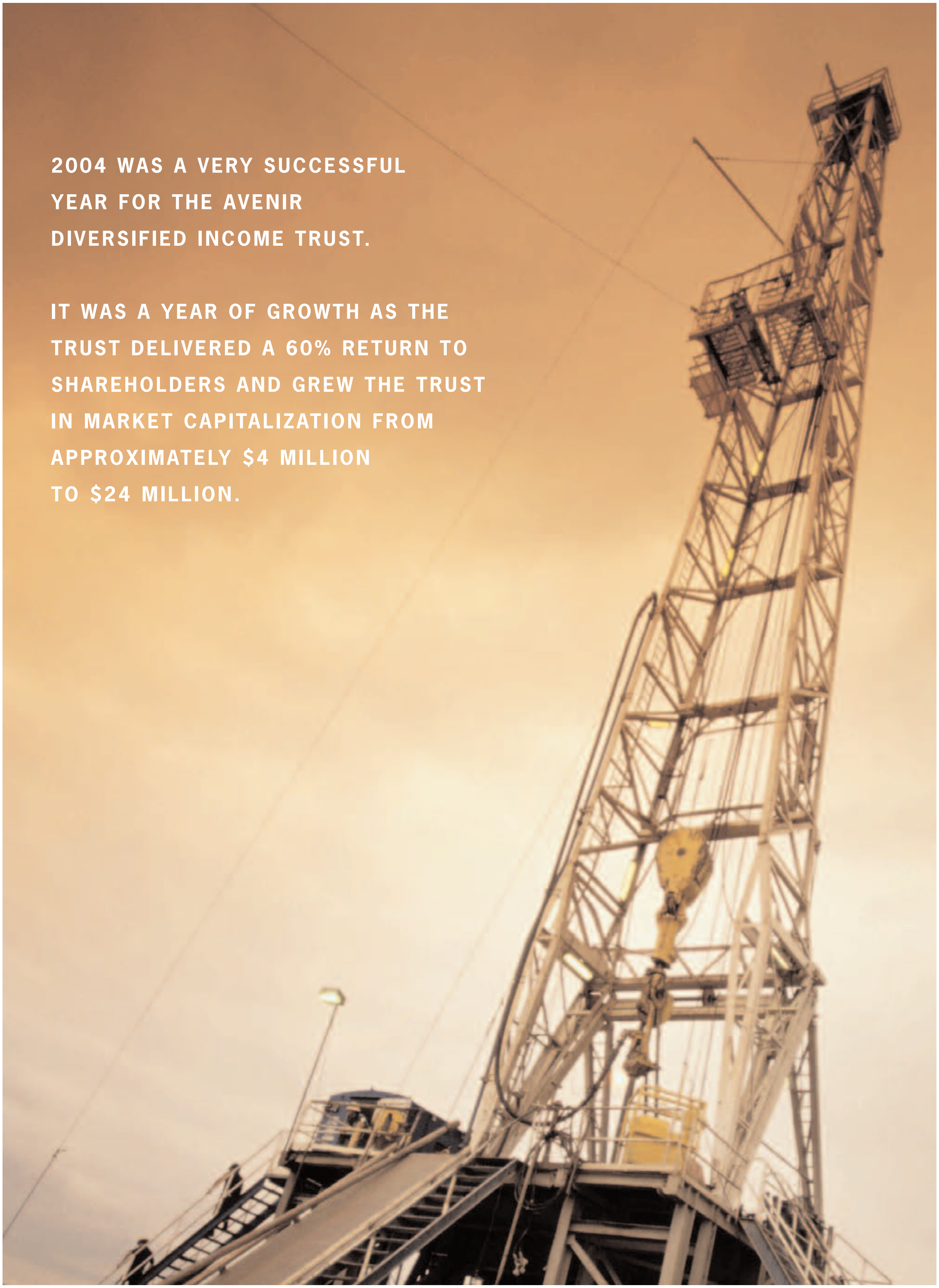
AVENIR DIVERSIFIED INCOME TRUST

ANNUAL
REPORT
2004



2004 WAS A VERY SUCCESSFUL YEAR FOR THE AVENIR DIVERSIFIED INCOME TRUST.

IT WAS A YEAR OF GROWTH AS THE TRUST DELIVERED A 60% RETURN TO SHAREHOLDERS AND GREW THE TRUST IN MARKET CAPITALIZATION FROM APPROXIMATELY $4 MILLION TO $24 MILLION.

2004 FINANCIAL HIGHLIGHTS & YEAR IN REVIEW

For the year ended	December 31		
	2004	2003 (restated)[4]	% Change
FINANCIAL			
Gross Revenue	25,047,961	5,219,610	380
Net Revenue	21,907,316	4,451,033	398
Cash Flow From Operations[1]	10,579,736	2,362,525	349
Cash Flow Per Unit[1] – Basic	1.86	1.28	45
Distributions	6,671,281	1,853,871	260
Distributions Per Unit – Basic	1.17	1.01	16
Distribution Payout Ratio[2]	63%	78%	19
% of Distributions Taxed as Income	75%	68%	10
Net Income (loss)	4,014,451	446,843	798
Net Income (loss) Per Basic Unit	0.71	0.24	196
Total Assets	155,314,853	22,430,980	592
Oil and Gas Working Cap. (Net Debt)[1]	(29,663,555)	(4,241,206)	599
Financial Services Working Cap.[1]	663,178	–	100
Real Estate Working Capital (Net Debt including mortgages)[1]	(14,360,246)	–	100
Energy Services Working Capital (Net Debt)[1]	(1,408,299)	–	100
Wtd. Avg. Common Shares Outstanding – Basic	5,685,210	1,841,437	209
Common Shares Outstanding	11,671,524	2,766,836	322
OPERATING			
Production			
Oil and NGL's – bbls per day	431	239	80
Gas – mcf per day	4,336	767	465
Total Boe[3] per day	1,153	367	214
Boe[3] per day Exit Rate	2,900	660	193
Average Pricing			
Oil & NGL ($/Bbl) before hedging	44.11	36.19	22
Oil & NGL ($/Bbl) after hedging	39.66	35.08	13
Natural Gas ($/mcf)	6.46	5.97	8
Average Price Per Boe[3] before hedging	40.20	36.35	11
Average Price Per Boe[3] after hedging	38.53	35.62	8
Gross Reserves (Proved plus Probable 6:1)			
Natural Gas (Mmcf)	19,543.7	4,375.5	355
Oil & NGL (Mmbl)	3,849.9	730.0	429
Total (Mboe)[3]	7,107.2	1,459.3	387

1 Cash flow from operations, cash flow per unit, net back, and working capital (net debt) are not recognized measures under Canadian generally accepted accounting principles (GAAP). Cash flow from operations is calculated by taking net income and adding back non-cash balances such as depletion, depreciation and amortization, asset retirement obligation accretion, gain on sale of investments, compensation expense, unrealized loss on financial instruments and unsuccessful acquisition and re-organizational costs. Working capital (net debt) is calculated by taking current assets less current liabilities not including current portion of mortgages (upon mortgage maturity it is the Trust's intention to renew the mortgages on a long term basis at or below current rates) and long-term debt. Management believes that these measures are useful supplemental measures to analyze operating performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments. The Trust's method of calculating these measures may differ from other issuers, and accordingly, they may not be comparable to measures used by other issuers. Investors should be cautioned that "Cash Flow From Operations" and "Cash Flow From Operations Per Unit" should not be construed as an alternative to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP.

2 Distribution Payout Ratio is calculated by dividing the Distributions by the Cash Flow From Operations.

3 Natural Gas conversion ration of 6:1

4 Certain comparative figures for prior years have been retroactively restated to incorporate the fifteen-for one unit consolidation and the retroactive application of the changes in accounting policies for asset retirement obligations and transportation charges, as described in notes 3 and 20 to the consolidated financial statements for the years ended December 31, 2004 and 2003.

FORWARD LOOKING STATEMENTS

Except for historical financial information contained herein, the matters discussed in this document may be considered forward-looking statements. Such statements include declarations regarding management's intent, belief or current expectations. Prospective investors are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties; actual results could differ materially from those indicated by such forward-looking statements. Among the important factors that could cause actual results to differ materially from those indicated by such forward-looking statements are: (i) that the information is of a preliminary nature and may be subject to further adjustment, (ii) the possible unavailability of financing, (iii) risks related to the exploration and development of oil and gas properties, (iv) the impact of price fluctuations and the demand and pricing for oil and natural gas, (v) the seasonal nature of the business, (vi) start-up risks, (vii) general operating risks, (viii) dependence on third parties, (ix) changes in government regulation, (x) the effects of competition, (xi) dependence on senior management, (xii) financial condition of real estate tenants and financial services counterparts, (xiii) impact of the Canadian economic conditions or the demand for real estate leasing opportunities, (xiv) fluctuations in currency exchange rates and interest rates.

PRESIDENT'S MESSAGE

Avenir Diversified Income Trust continued to enjoy very good success during 2004. For the year-ended December 31, 2004, the Trust delivered a 38.5% return to unitholders, including $2.25 per unit capital appreciation and $1.104 per unit in distributions paid. Distributions were increased twice for a total of 20% and distributions represented a 63% payout of the cash flow for the year.

It was another year of growth. The market capitalization of the Trust grew from approximately $24 million to $130 million by the end of December 2004. The number of units outstanding increased with two financings, the first closed in June 2004 at a price of $7.50 per unit for gross proceeds of $28.75 million and the second closed in November 2004 at a price of $9.00 per unit, for gross proceeds of $40.25 million.

Since inception, the Trust has followed a corporate philosophy that combines the cash flow streams from three business units: Energy (oil & gas and energy services), Financial Services and Real Estate. The strategy of the Trust is to diversify risk and maintain attractive yields, with sustainable distributions. Through acquisition, the Trust has been able to successfully grow each of these business units accretively throughout 2004 and generate steady income and capital appreciation for unitholders. Over the next three years, the Trust will continue with this growth strategy, building each business unit to a size of independence. From the outset, the three business units have been organized to possess their own trust-like characteristics, operate independently, and be managed by experienced industry individuals, with significant input at the Trust level. Outlined next are the strategies of each business unit.

Within the Energy business unit, in the oil & gas division, we look to target opportunities of less than 1,000 boe per day which are too small for pure-play energy trusts, maintain the Trust's reserve life index at 6 to 8 years and hedge commodity price exposure. Within the energy services division, we look to continue to pursue diversification opportunities which are economic and accretive in the essential production services segment of the industry.

In our Financial Services business unit, our focus is on providing high-yield financial services contracts to businesses outside the energy and real estate industries. In this business unit we look for opportunities which allow us to wrap a contract around a stream of cash flow. We will look to further diversify this business unit's portfolio across multiple business lines.

The Real Estate business unit has proven to be the hardest to transact on throughout 2004 as we look to target and acquire real estate properties that will yield a 9-12% return. Our target range of leverage is 65% and in this business unit we will continue to identify properties that are too large for individual investors yet too small for other REIT's.

HIGHLIGHTS FROM 2004 INCLUDE:

- Listing on the TSX in July 2004;
- Completing two equity financings totaling $69 million;
- Diversifying the Energy portfolio by expanding into the energy services sector;
- Increasing in distributions;
- Completing approximately:
  - $74.3 million in oil and gas acquisitions;
  - $5.8 million in energy services acquisitions;
  - $9.2 million in financial services contracts; and
  - $20.0 million real estate acquisition.

So far in 2005 to date, we have already completed a $126.5 million equity financing at $10.90 per unit, closed a $29.6 million oil and gas acquisition and announced a $57.8 million financial services acquisition.

We continue to evaluate opportunities in all three segments of our Trust and are confident that we will continue to grow in size, liquidity, diversity, cashflow and in distributions, as we have demonstrated since our inception. We will continue to implement a strategic commodity hedging program for a portion of our oil and gas production; this will provide some protection from price weakening but still provides the opportunity to participate in commodity price appreciation.

In closing, we would like to express our appreciation to our employees and consultants for their efforts, to our Board of Directors and our Advisors for their guidance, and to our unitholders for their continued support as we execute our business plan.

We look forward to a successful 2005.

Submitted on behalf of the Board of Directors by:

WILLIAM M. GALLACHER	GARY DUNDAS
President & CEO	Vice President Finance & CFO

FINANCIAL RESULTS

The net income for the year ended December 31, 2004 was $4,014,451 which is up 798% versus the $446,843 net income for the year ended December 31, 2003. The Trust recorded net income of $2,955,693 for the three months ended December 31, 2004 compared to a loss of $72,767 for the three months ended December 31, 2003. The three months ended December 31, 2004 net income has been positively impacted by recognition of $1,742,280 non-cash mark-to-market opportunity gain related to risk management contracts.

Cash flow from operations was $10,579,736 for the year ended December 31, 2004, up 349% as cash flow for the year ended December 31, 2003 was $2,362,525. The cash flow for the fourth quarter 2004 was $4,991,022 or $0.53 per unit up 485%, compared to the fourth quarter 2003 of $853,418 or $0.31 per unit. The increase in cash flow was primarily the result of the growth in the Trust's business units, including: oil and gas acquisitions made, continued high commodity prices, additional financial services contracts, and the initial inclusion of the Western Spirit real estate acquisition at the end of March 2004.

The Trust distributed $6,671,281 or $1.17 per unit for the year ended December 31, 2004 which is up 260% over the $1,853,871 or $1.01 per unit distributed for the year ended December 31, 2003. For the fourth quarter 2004 the Trust distributed $3,053,499 ($0.32 per unit), to unitholders compared to $725,892 ($0.26 per unit) for the quarter ended December 31, 2003. On August 19, 2004 the Trust announced a 10% increase in the monthly distribution beginning with the August distribution payable September 15, 2004. On December 16, 2004 the Trust announced a further 10% increase in the monthly distribution beginning with the December distribution payable January 15, 2005. The 2004 year end payout ration was 63% of cash flow and the fourth quarter payout was 60% of cash flow.

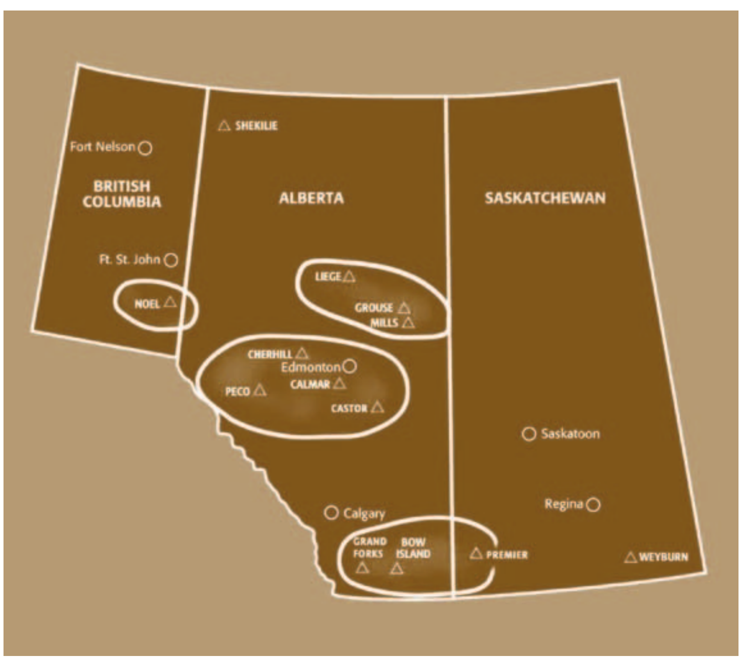
BUSINESS UNIT OPERATIONS

I. ENERGY BUSINESS UNIT

a. OIL & GAS OPERATIONS

Operationally, the Oil and Gas business unit had an extremely busy year growing through acquisition with production increasing from 660 barrels of oil equivalent (boe) per day at the end of the fourth quarter 2003 to 2,900 boe per day at the end of the fourth quarter 2004.

On June 30, 2004, the Trust completed two oil and gas property acquisitions in two core areas, Northeast Alberta and Southern Alberta. The acquisitions totalled $9.9 million (plus related costs and fees) and adds approximately 340 boe per day (82% gas and 18% light oil). The reserve life index for these properties, based on a proved plus probable reserve estimate was 8.0 years. The acquisition equated to approximately $30,000 per producing boe, based on the stabilized production levels.



On September 30, 2004, the Trust acquired the shares of a private oil and gas company, from Lightning Energy Ltd. The $32.7 million acquisition (plus related costs and fees), resulted in the Trust acquiring assets in N.E. British Columbia and Shekilie and Central Alberta, with estimated production of approximately 1,000 boe per day (60% natural gas and 40% light oil). Several development prospects identified to provide growth through drilling or farm-out opportunities for the Trust. The reserve life index for the properties, based on the proved plus probable reserve estimate, is approximately 8.2 years. After accounting for $2.5 million in undeveloped land and seismic, the acquisition equates to production and reserve valuations of approximately $29,800 per producing boe.

Another acquisition was completed on December 17, 2004. Avenir closed the acquisition of various properties from PrimeWest Energy Inc. and PrimeWest Gas Corp. for $30.0 million (plus related costs and fees). The acquisition provides Avenir with approximately 1,020 boe per day (80% light oil, 20% natural gas) of production and long life reserves in its core areas of southern Alberta and southwest Saskatchewan.

On March 28, 2005 the Trust announced that 91.38% of the issued and outstanding common shares of Val Vista Energy Ltd. ("Val Vista") have been tendered to the offer dated February 15, 2005 ("Offer") to purchase all of the issued and outstanding Val Vista shares. The Trust will proceed to take up and pay for all of the Val Vista share deposited under the Offer. The Trust will also proceed to acquire all of the remaining outstanding Val Vista shares pursuant to the compulsory acquisition provisions of the Business Corporations Act. The consideration given to the Val Vista shareholders will be a combination of cash and Trust Units. The cash portion has a maximum of $12, 666,600 and the maximum number of Trust Units to be issued is 1,183,795.

OIL AND NATURAL GAS RESERVES SUMMARY

To follow is a consolidated summary combining two reserve reports at December 31, 2004. The table is based on a McDaniel & Associates Consultants Ltd. ("McDaniel") Report dated March 2, 2005, evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves of the Trust as at December 31, 2004, and a Gilbert Laustsen Jung Associates Ltd. ("GLJ") Report dated January 19, 2005, which was prepared for the PrimeWest Property Acquisition as at December 31, 2004. Both reports use McDaniel Price forecast at December 31, 2004. The tables summarize the data contained in the Reports and as a result may contain slightly different numbers than such reports due to rounding. Also due to rounding, certain columns may not add exactly. The recovery and reserve estimates of the Trust's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

Reserves Data – Forecast Prices and Costs Summary of Oil and Gas Reserves Effective December 31, 2004

	Gross Reserves				Net Reserves			
	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas
	Mbbls	Mbbls	Mbbls	Mmcf	Mbbls	Mbbls	Mbbls	Mmcf
Proved								
Developed Producing	2324.4	593	50	12533.6	2005.6	537.7	40.5	10441.2
Developed Non-Producing	43	81	5.9	879.8	35.2	74	4.4	757.5
Undeveloped	56	0	1	901.1	53	0	1	635.1
Total Proved	2423.4	674	56.9	14314.5	2093.8	611.7	45.9	11833.8
Total Probable	558.6	117.3	19.7	5229.2	470.9	106.9	15.3	4202.4
Total Proved plus Probable	2982	791.3	76.6	19543.7	2564.7	718.6	61.2	16036.2

Net Present Value of Future Net Revenue of Oil and Gas Reserves

The net present value of future net revenue attributable to the Trust's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel and GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Trust's reserves estimated represent the fair market value of those reserves.

	Before Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Developed Producing	81,842	70,429	62,441	56,417	51,672
Developed Non-Producing	6,455	5,631	5,035	4,580	4,218
Undeveloped	3,089	2,548	2,157	1,862	1,631
Total Proved	91,386	78,608	69,633	62,858	57,520
Total Probable	28,681	20,660	15,931	12,859	10,731
Total Proved plus Probable	120,066	99,268	85,564	75,717	68,251

RESERVE DISCLOSURE FOR AVENIR DIVERSIFIED INCOME TRUST BASE (LESS PRIMEWEST RESERVES)

With respect to reserve disclosure for the financial year ended December 31, 2004, the Trust was subject to NI 51-101, which was implemented in September, 2003. NI 51-101 prescribes standards for the preparation and disclosure of oil and gas reserves and related estimates, requires the annual public filing of certain of those estimates and other information pertaining to oil and gas activities, and specifies responsibilities of corporate directors. In particular, the definitions of proved reserves and probable reserves contain specific quantifications of levels with respect to certainty of recoverability of 90% for proved reserves and of 50% for proved plus probable reserves.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls	Barrels
Mbbls	thousand barrels
Bbls/d	barrels per day
Mmbbls	million barrels
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
MMBTU	million British Thermal Units

Other

AECO	EnCana Corporation's natural gas storage facility located at Suffield, Alberta.
BOE	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one Bbl of oil, unless otherwise specified. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.
BOE/d	barrels of oil equivalent per day.
COGPE	means Canadian oil and gas property expense, as defined in the Tax Act.
MBOE	means thousand barrels of oil equivalent.
McfGe	means thousand cubic feet of gas equivalent.
MMBOE	means million barrels of oil equivalent.
OOIP	means original oil in place.
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
ºAPI	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electrical power.
3D	three dimensional.
Darcies	means the measure of permeability (being the ease with which a single fluid will flow through connected pore space when a pressure gradient is applied).
porosity	means the measure of the fraction of pore space of a reservoir.

DESCRIPTION OF THE BUSINESS AND PROPERTIES OF THE TRUST AND ITS OPERATING ENTITIES

The following is a summary of the principal properties, both oil and gas and real estate, currently held by the Trust, but does not include information with respect to the Prime West Properties.

PRINCIPAL PROPERTIES

The following is a description of the Trust's oil and natural gas properties as at December 31, 2004. Production stated is net production to the Trust and, unless otherwise stated, is average production for 2004. Reserve amounts are stated as at December 31, 2004 based on forecast costs and prices as evaluated in the McDaniel Report (see "Reserves Data"). The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2004.

BOEs (Mcfe or other applicable units of equivalency) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf's/bbl (or an Mcfe conversion ratio of 1 bbls/ 6 Mcf) is based on energy equivalence of conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

The Trust currently has interests in approximately 312 productive oil wells and 239 productive gas wells located in 78 properties in Western Canada. Approximately 73% of the value of the properties of the Trust is comprised of interests in 10 properties. These properties are summarized in the table below:

Properties of the Trust	Property Owner	Total Proved Reserves (MBOE)(1)	Number of Gross Wells(2)	Number of Net Wells
Noel	Avenir / Burlington	809.2	18	6.3
Liege	Bonavista	390.9	29	15.7
Shekilie	Avenir / Apache	278.2	13	3.9
Mills Grouse	CNRL	274.9	135	20.3
Killam	Cresent Point	198.6	49	14.8
Weyburn	Avenir / Cresent Point	132.0	11	3.8
Cherhill	Avenir	119.0	3	2.7
Covington	Avenir	83.7	3	1.5
Bow Island	Celtic	67.3	16	3.6
Calmar	Avenir	66.8	2	2
Total		2420.6	279	74.6

Notes:

1. Proven plus probable working interest and royalty interest reserves as of December 31, 2004. All such reserves are based on the
2. McDaniel Report – Forecast Prices. See "Oil and Natural Gas Reserves".
3. Wells listed are considered productive and do not include suspended wells.

Noel, British Columbia

The Noel property is located in British Columbia from Blocks G/93–P-1 to H/93-P-7 approximately 110 kilometres south of Fort St. John. The Noel area is west of the Elmworth gas field and northwest of the Wapiti gas field, of the Alberta Deep Basin. The Trust holds various working interests up to 70% in 204 units (equivalent to approximately 51 sections) of land. The majority of the Trust's production is obtained from the gas bearing Cadotte and Falher formations. The Trust operates approximately 42% of their production while the remainder is operated by Burlington Resources Canada Ltd. Wells in the Noel area are characterized by low decline rates and high reserve life indices.

Sales gas is processed through Burlington Resources Canada Ltd.'s Elmworth Deep Cut Gas Plant. The multi-zone nature of this area is well known and the Trust's lands are prospective for gas production from the Nikanissin, Cadomin, Bluesky/Gething, Falher, Cadotte and Doe Creek formations, however most of the Trust's current wells produce from the Falher and Cadotte formations. Reserves assigned to this property based on the McDaniel Report dated December 31, 2004 are total proved reserves of 809 Mboe and proved plus probable reserves of 1,220 Mboe.

Liege, Alberta

The Liege property is located in northern Alberta in Townships 89 and 90, Ranges 20-22 W4M, approximately 100 kilometres west of Fort McMurray. The Trust holds interests of 47% to 77% in 126 sections of contiguous land. Gas production is obtained from the Cretaceous Mannville group and the Devonian age Grosmont formation. The gas is sweet and is processed through facilities owned in part by the Trust. Reserves assigned to this property based on the McDaniel Report are total proved reserves of 391 Mboe and proved plus probable reserves of 513 Mboe.

Shekilie, Alberta

The Shekilie property is located in the extreme north of Alberta, Townships 118-120, Ranges 7 and 8 W6M, approximately 450 kilometres north of Grande Prairie, Alberta. The Trust holds varying interests up to 70% in 11.2 sections of land. Gas production is obtained from the Sulphur Point and Slave Point formations, and oil and gas production from the Keg River Formation. The gas is sour and all gas and liquids are processed through separate facilities operated by an independent third party. The Trust operates approximately 50% of its production with the balance being operated by an independent third party. Reserves assigned to this property based on the McDaniel Report are total proved reserves of 278 Mboe and proved plus probable reserves of 373 Mboe.

Mills/Grouse, Alberta

The Mills and Grouse fields are located 170 kilometres south of Fort McMurray, Alberta. The properties consist of 13,450 acres of developed land and 15,500 acres of undeveloped land. The Trust's interest in these properties consists of 94 (13 net) producing gas wells and 55 suspended (8 net) gas wells. All production is from shallow, sandstone reservoirs occurring at depths between 250 and 500 meters. At each well, surface facilities generally consist of gas metering and water storage tanks. The Trust does not operate any facilities or wells in this area. Raw gas is processed at two facilities one of which the Trust has a 20% interest in. Total reserves attributed in the McDaniel Report to the Mills and Grouse properties are 275 Mboe total proved and 341 Mboe total proved plus probable.

Killam, Alberta

The Killam property is located 90 miles southeast of Edmonton, Alberta, in Township 42, Range 14 W4M. The Trust has interests in five sections of land, two of which have production. The Trust holds working interests ranging from 17.5 % to 35.7%. The majority of production originates from the Crescent Point Energy Trust: Glauconitic FF pool. Reserves assigned to this property based on the McDaniel Report are total proved of 199 Mboe and proved reserves plus probable reserves of 259 Mboe.

Weyburn, Saskatchewan

This Weyburn property is located 115 kilometres southeast of Regina. The Weyburn wells produce light quality sweet crude from the Midale formation at a depth of 1300 meters. The Trust has an interest in an oil battery that separates the crude and water and disposes of the water into a water disposal well. Surface facilities at each well consists of a conventional pumping unit and may include a water and oil storage tank if the well is not flow lined to a central facility. Total reserves attributed in the McDaniel Report to the Weyburn Property are 132 Mboe total proved and 203 Mboe total proved plus probable.

Cherhill, Alberta

The Cherhill property is located 80 kilometres northwest of Edmonton. The property consists of three net Banff oil wells that produce a medium gravity sour crude from the Banff formation at a depth of 1,350 meters. Surface facilities consist of conventional pumping units with flow lines to gather the produced oil, water and gas. Solution gas is conserved and oil and water volumes are processed at third party facilities. The Trust operates all of the Cherhill oil wells. The Trust has interests in 1,920 acres of developed land (1,920 net acres). Total reserves attributed in the McDaniel Report to the Cherhill Property are 119 Mboe total proved and 143 Mboe total proved plus probable.

Covington, Saskatchewan

The Covington property is located 48 kilometres southwest of Swift Current, Saskatchewan. The Trust holds varying interest ranging from gross overriding royalties to 70% working interests in seven producing oil wells. Reserves assigned to this property based on the McDaniel Report are total proved of 84 Mboe and proved reserves plus probable reserves of 104 Mboe .Mills/Grouse, Alberta

Bow Island, Alberta

The Bow Island property is located 200 kilometres southeast of Calgary. The property consists of interests varying from 10.0% to 32.71%. The Bow Island wells produce a medium gravity crude (26 API) from the Sawtooth F Pool at a depth of 1100 meters. The Trust has a 32.71% working interest in an oil battery that was constructed in 2003. The battery separates produced oil, water and gas. Each well site is equipped with a screw pump and a flow line that allows produced oil, gas and water to be gathered and processed at the battery. The Trust does not operate any of the wells in the Bow Island property. Total reserves attributed in the McDaniel Report to the Bow Island Property are 67 Mboe total proved and 86 Mboe total proved plus probable.

Calmar, Alberta

The Calmar property is located 38 kilometres southwest of Edmonton. The property consists of two net producing gas wells, and no suspended wells and is situated on 1280 acres (1280 net acres) of developed land. The Calmar wells produce sweet gas from the Cardium formation. Surface facilities consist of a compressor, flow line and meter at each well that sends produced gas to a third party facility for further processing. In addition to these facilities, each well site has a small tank to handle minor amounts of produced liquid. Reserves assigned to this property based on the McDaniel Report are total proved of 67 Mboe and proved reserves plus probable reserves of 82 Mboe.

OIL AND NATURAL GAS RESERVES FOR AVENIR DIVERSIFIED INCOME TRUST (LESS PRIMEWEST RESERVES)

In accordance with NI 51-101, McDaniel prepared the McDaniel Report dated March 2, 2005, evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves of the Trust as at December 31, 2004. The McDaniel Report evaluated, effective as at December 31, 2004, the Trust's oil, NGL and natural gas reserves. The tables below are a summary of the Trust's oil, NGL and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the McDaniel Report based on constant and forecast price and cost assumptions, and the information set forth below is prepared in accordance with standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables summarize the data contained in the McDaniel Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. The net present value of future net revenue attributable to the Trust's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Trust's reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Trust's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The McDaniel Report is based on certain factual data supplied by the Trust and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Trust's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Trust to McDaniel and accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs Summary of Oil and Gas Reserves

Summary of Oil and Gas Reserves: Effective December 31, 2004

	Gross Reserves				Net Reserves			
	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas
	Mbbls	Mbbls	Mbbls	Mmcf	Mbbls	Mbbls	Mbbls	Mmcf
Proved								
Developed Producing	1,153	16	40	10,969	999	15	30	9,129
Developed Non-Producing	43	0	6	880	35	0	4	758
Undeveloped	0	0	0	83	0	0	0	70
Total Proved	1,196	16	46	11,932	1,034	15	35	9,957
Total Probable	354	4	18	4,771	297	4	13	3,847
Total Proved plus Probable	1,550	20	64	16,703	1,331	19	48	13,804

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Developed Producing	58,581	50,728	44,986	40,593	37,117
Developed Non-Producing	3,624	3,031	2,631	2,343	2,124
Undeveloped	188	176	164	153	143
Total Proved	62,393	53,935	47,781	43,088	39,383
Total Probable	23,037	16,538	12,674	10,168	8,439
Total Proved plus Probable	85,430	70,473	60,455	53,256	47,822

Pricing Assumptions – Constant Prices and Costs

McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2004 in estimating the Trust's reserves data using constant prices and costs.

Summary Of Pricing Assumptions as of December 31, 2004 – Constant Prices And Cost[1]

	Oil[1]				Natural Gas[1]		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40º API ($Cdn/bbl)	Hardisty Heavy ($Cdn/bbl)	Cromer Medium 29.3º API ($Cdn/bbl)	Natural Gas[1] AECO Gas Price ($Cdn/MMBTu)	Natural Gas Liquids Fob[1] Field Gate ($Cdn/BBL)	Exchange Rate[2] ($US/$Cdn)
Historical							
2002	26.08	40.33	26.57	35.48	4.04	29.73	0.638
2003	31.07	43.66	26.26	37.55	6.66	36.91	0.769
2004	41.38	52.96	29.11	45.75	6.88	43.22	0.769
December 31, 2004	43.45	46.54	24.33	32.12	6.79	37.73	0.831

Notes:

1. Constant pricing was supplied by McDaniel Constant Prices and Costs.
2. The exchange rate used to generate the benchmark reference prices in this table.
3. NGL mix based on 45% propane, 35% butane and 20% natural gasolines.

Pricing Assumptions - Forecast Prices and Costs

McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2004 in estimating the Trust's reserves data using forecast prices and costs.

Summary Of Pricing And Inflation Rate Assumptions As Of December 31, 2004 Forecast Prices And Costs

	Oil[1]				Natural Gas[1]			
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40º API ($Cdn/bbl)	Hardisty Heavy 12º API ($Cdn/bbl)	Cromer Medium 29.3º API ($Cdn/bbl)	Natural Gas[1] AECO Gas Price ($Cdn/GJ)	Natural Gas Liquids Fob[1] Field Gate ($Cdn/BBL)	Inflation Rates[2] %/Year	Exchange Rate[3] ($US/$Cdn)
Forecast								
2005	42.00	49.60	29.40	43.50	6.45	37.20[4]	2.00	0.830
2006	39.50	46.60	29.90	40.90	6.20	35.10	2.00	0.830
2007	37.00	43.50	27.90	38.20	6.05	33.00	2.00	0.830
2008	35.00	41.10	26.30	36.00	5.80	31.20	2.00	0.830
2009	34.50	40.50	25.90	35.50	5.70	30.80	2.00	0.830

Notes:

1. This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer. Prices are from the January 1, 2005 McDaniel Forecast Prices and Costs.
2. Inflation rates for forecasting prices and costs. The inflation rate of two percent (2%) per annum is used to forecast the annual increase in oil and gas prices, operating costs and capital costs.
3. Exchange rates used to generate the benchmark reference prices in this table.
4. NGL mix based on 45% propane, 35% butane and 20% natural gasolines.

The weighted average realized sales prices by us for the year ended December 31, 2004 was $6.52/Mcf for natural gas, $43.66/Bbl for crude oil and $38.73/Bbl for NGL's.

Reserves Reconciliation

The following table sets forth a reconciliation of the Trust's total net proved, probable and total net proved plus probable reserves as at December 31, 2004 against such reserves as at December 31, 2003 based on forecast price and cost assumptions.

	Light and Medium Crude Oil			Heavy Oil			Associated & Non-Associated Gas		
	Net Proved Reserves	Net Probable Reserves	Net Proved Plus Reserves	Net Proved Reserves	Net Probable Reserves	Net Proved Plus Reserves	Net Proved Reserves	Net Probable Reserves	Net Proved Plus Reserves
	Mbbls	Mbbls	Mbbls	Mbbls	Mbbls	Mbbls	Mmcf	Mmcf	Mmcf
December 31, 2003	484.8	141.1	625.9	0.0	0.0	0.0	3037.3	693.2	3730.5
Extensions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improved Recovery	48.1	8.9	57.0	0.0	0.0	0.0	283.2	65.2	348.4
Technical Revisions	43.0	–7.6	35.4	20.1	4.0	24.1	283.5	–204.6	78.9
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	577.6	156.5	734.1	0.0	0.0	0.0	7677.8	3,295.0	10,972.8
Dispositions	–10.3	–1.9	–12.2	0.0	0.0	0.0	–5.8	–1.8	–7.6
Economic Factors	1.0	0.0	1.0	0.0	0.0	0.0	1.0	0.0	1.0
Production	–110.2	0.0	–110.2	–5.1	0.0	-5.1	–1320.0	0.0	–1320.0
December 31, 2004	1,034.0	297.0	1,331.0	15.0	4.0	19.0	9,957.0	3,847.0	13,804.0

	Net Natural Gas Liquids			Total Net Oil Equivalent		
	Net Proved Reserves	Net Probable Reserves	Net Proved Reserves	Net Proved Reserves	Net Probable Reserves	Net Proved Reserves
	Mbbls	Mbbls	Mbbls	MBOE	MBOE	MBOE
December 31, 2003	25.3	6.1	31.4	1016.3	262.7	1279.0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0
Improved Recovery	0.3	0.1	0.4	95.6	19.9	115.5
Technical Revisions	–2.4	–3.1	–5.5	108.0	–40.8	67.2
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	18.8	9.9	28.7	1,876.0	715.5	2,591.6
Dispositions	0.0	0.0	0.0	–11.3	–2.2	–13.5
Economic Factors	0.0	0.0	0.0	1.2	0.0	1.2
Production	–7.0	0.0	–7.0	-342.3	0.0	–342.3
December 31, 2004	35.0	13.0	48.0	2,743.5	955.2	3,698.7

Oil and Gas Properties

A summary description of the Trust's major producing and exploration properties is set out below. References to gross volumes refer to total production. References to net volumes refer to the Trust's working interest share before the deduction of royalties payable to others.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Trust has a working interest as at December 31, 2004.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing[3]		Producing		Non-Producing	
	Gross[1]	Net[2]	Gross	Net	Gross	Net	Gross	Net
British Columbia	3	1.1	1	0.4	22	7	15	3.1
Alberta	156	40	59	16.1	217	54	58	17.2
Saskatchewan	153	13.5	34	3.2	0	0	0	0
Total	312	54.6	94	19.7	239	61	73	20.3

Notes:

1. "Gross" wells means the number of wells in which the Trust has a working interest.
2. "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Trust's percentage working interest therein.
3. Non-producing includes wells shut-in for economic reasons, wells not capable of production and wells used for disposal of water.

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which we have an interest. The Trust does not have any properties that are unproductive at this time.

The following table sets out the Trust's undeveloped land holdings as at December 31, 2004.

	Undeveloped Acres	
	Gross	Net
British Columbia	39,040	10,305
Alberta	236,613	42,144
Saskatchewan	480	240
Total	276,133	52,689

Additional Information Concerning Abandonment and Reclamation Costs

The Trust typically estimates well abandonment costs area by area. Such costs are included in the McDaniel Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the McDaniel Report for 92 net wells under the proved reserves category is an estimated $2,191,000 discounted at 10%, of which a total of approximately $350,000 is estimated to be incurred in 2005, 2006 and 2007. (This estimate does not include expected reclamation costs for surface leases). Expected future abandonment costs related to facilities are expected to match the salvage value recovery.

The Trust typically estimates that the additional reclamation costs associated with both active and inactive surface leases and wells not captured in the McDaniel Report is $2,270,512 discounted at 10%. The abandonment cost for each surface lease was estimated using the lease liability rating system that is available through the Energy Resources Conservation Board. An average abandonment cost of $30,000 per wellbore was used in the McDaniel Report and is believed to be representative of a typical abandonment operation.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Trust has participated in during the year ended December 31, 2004:

	Gross	Net
Light and Medium Oil	2	0.2
Natural Gas	3	1.4
Service	0	0
Dry	0	0
Total:	5	1.6

In 2005, the Trust will focus the development activities towards the Mills Grouse properties and low risk horizontal well opportunities in Southeast Saskatchewan. Development at Mills Grouse occurred in the first quarter and consisted of the drilling of two gas wells (0.4 net, 1 success and 1 dry hole and abandoned) and six re-completions (1 net). Net production added is estimated to be 250 Mcf/d. The Saskatchewan development program will proceed in the third quarter, pending regulatory approval of the proposed horizontal wells.

Production History

The following table indicates the Trust's average daily production from important fields for the year ended December 31, 2004:

	Light and Medium Crude Oil & NGL's	Heavy Oil	Gas	BOE
	(Bbls/d)	(Bbls/d)	(Mcf/d)	(BOE/d)
ALBERTA PROPERTIES				
Liege	0	0	1,480	247
Shekilie	120	0	210	155
Mills Grouse	0	0	1,525	254
Killam	86	0	10	88
Cherhill	35	0	140	58
Covington	32	0	0	32
Bow Island	71	0	20	74
Calmar	0	0	275	46
Other	64	16	500	163
Total Alberta	408	16	4,163	1,117
BRITISH COLUMBIA PROPERTIES				
Noel	3	0	2,720	456
Rigel	17	0	30	22
Total British Columbia	20	0	2,750	478
SASKATCHEWAN PROPERTIES				
Weyburn	48	0	0	48
Benson	44	0	0	44
Covington	32	0	0	32
Other	37	0	40	44
Total Saskatchewan	161	0	40	168
TOTAL	589	16	6,953	1,763

DESCRIPTION OF THE PRIMEWEST PROPERTIES

Grand Forks

The Grand Forks property is located in Townships 10-12, Ranges 11-13 W4M approximately 22 miles northeast of Taber in southeast Alberta. The Trust holds various working interests averaging 84% in approximately 70 producing wells/zones spread over approximately 40 sections of land. Virtually all of the wells and all the production facilities are operated by the Trust. Heavy oil (22-25 degrees API) is produced from the Jurassic age Sawtooth Formation with high water cuts while gas is produced from the Bow Island Formation and the Second White Specks. The oil is produced to three oil batteries owned and operated by the Trust while the gas is gathered to compressor stations also owned and operated by the Trust. Current working interest production is 512 bbls per day of oil and 604 mcf of gas per day. Reserves attributed to the Trust's interest in this property in a GLJ report dated January 19, 2005 report are 805 Mbbls of oil equivalent total proved and 938 Mbbls of oil equivalent on a total proved plus probable basis. The Trust has identified opportunities to increase natural gas production from the Second White Specks through infill and delineation drilling as well as Sawtooth development drilling.

Eagle Lake

The Eagle Lake property is located in Township 31, Range 20 W3M 15 miles northeast of Kindersley in west central Saskatchewan. The Trust holds a 9.38% interest in the Eagle Lake Viking Voluntary Unit. An independent third party producer operates both the wells and facilities. Current working interest production is 47.8 bbls per day of oil. Reserves attributed to the Trust's interest in this property in a report by GLJ dated January 19, 2005 are 520 Mbbls of oil equivalent total proved and 600 Mbbls of oil equivalent on a total proved plus probable basis.

Southwest Saskatchewan

The Southwest Saskatchewan property is located in Townships 15-17, Ranges 16-18 W3M 15 miles west of Swift Current. The Trust holds a 100% working interest in the East Beverly Cantuar Voluntary Unit in the Java oil field and a 50% working interest in the North Premier Unit #1. In total the Trust holds a 100% working interest in 29 unit and non-unit producing oil wells and a 50% working interest in 7 producing oil wells in the North Premier Unit. The Cantuar, Roseray and Shaunavon Zones all contribute to production and reserves on this property. Production is gathered and processed at facilities owned and operated by the Trust. Current working interest production is 350 bbls per day of oil and 415 mcf of gas per day. Reserves attributed to the Trust's interest in this property in a report by GLJ dated January 19, 2005 are 962 Mbbls of oil equivalent total proved and 1143 Mbbls of oil equivalent on a total proved plus probable basis. Some potential step-out drilling potential exists on this property.

Manyberries

The Manyberries property is located in the extreme southeast corner of the Province on Alberta in Township 5, Ranges 4-5 W4M. The Trust holds a 11.226% interest in the Manyberries Sunburst JJ Pool Unit. Current working interest production is 19.3 bbls per day. Reserves attributed to the Trust's interest in this property in a report by GLJ dated January 19, 2005 are 8 Mbbls of oil equivalent total proved and 10 Mbbls of oil equivalent on a total proved plus probable basis. Some potential step-out drilling potential exists on this property.

OIL AND NATURAL GAS RESERVES FOR THE PRIMEWEST PROPERTIES

In accordance with NI 51-101, GLJ prepared the PrimeWest Reserve Report dated January 19, 2005, evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves of the Prime West Properties as at December 31, 2004. The tables below are a summary of the PrimeWest Reserve Report NGL and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the PrimeWest Reserve Report based on constant and forecast price and cost assumptions, and the information set forth below is prepared in accordance with standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables summarize the data contained in the PrimeWest Reserve Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. The net present value of future net revenue attributable to the Prime West Properties reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Prime West Properties reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Prime West Property Acquisition's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The PrimeWest Reserve Report is based on certain factual data supplied by the Trust and GLJ's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Prime West Property Acquisition petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Trust to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted.

Prime West Property Acquisition Reserves Data – Forecast Prices and Costs Summary of Oil and Gas Reserves

Summary of Oil and Gas Reserves: Effective December 31, 2004

	Gross Reserves				Net Reserves			
	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas
	Mbbls	Mbbls	Mbbls	Mmcf	Mbbls	Mbbls	Mbbls	Mmcf
Proved								
Developed Producing	1,171	577	10	1565	1,007	523	10	1,312
Developed Non-Producing	0	81	0	0	0	74	0	0
Undeveloped	56	0	1	818	53	0	1	565
Total Proved	1,227	658	11	2,383	1,060	597	11	1,877
Total Probable	205	113	2	458	174	103	2	355
Total Proved plus Probable	1,432	771	13	2,841	1,234	700	13	2,232

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Developed Producing	23,261	19,701	17,455	15,824	14,555
Developed Non-Producing	2,831	2,600	2,404	2,237	2,094
Undeveloped	2,901	2,372	1,993	1,709	1,448
Total Proved	28,993	24,673	21,852	19,770	18,137
Total Probable	5,644	4,122	3,257	2,691	2,292
Total Proved plus Probable	34,636	28,795	25,109	22,461	20,429

Pricing Assumptions – Constant Prices and Costs

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of December 31st, 2004 in estimating the reserves data of the Prime West Properties using constant prices and costs.

Summary Of Pricing Assumptions as of December 31, 2004 – Constant Prices And Cost

	Oil[1]				Natural Gas[1]		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40º API ($Cdn/bbl)	Hardisty Heavy ($Cdn/bbl)	Cromer Medium 29.3º API ($Cdn/bbl)	Natural Gas[1] AECO Gas Price ($Cdn/MMBTu)	Natural Gas Liquids Fob[1] Field Gate ($Cdn/BBL)	Exchange Rate[2] ($US/$Cdn)
Historical							
2002	26.08	40.33	26.57	35.48	4.04	29.73	0.638
2003	31.07	43.66	26.26	37.55	6.66	36.91	0.769
2004	41.38	52.96	29.11	45.75	6.88	43.22	0.769
December 31, 2004	43.45	46.54	24.33	32.12	6.79	37.73	0.831

Notes:
1. Constant pricing was supplied by McDaniel Constant Prices and Costs.
2. The exchange rate used to generate the benchmark reference prices in this table.
3. NGL mix based on 45% propane, 35% butane and 20% natural gasolines.

Summary Of Pricing And Inflation Rate Assumptions As Of December 31, 2004 Forecast Prices And Costs

	Oil[1]				Natural Gas[1]			
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40º API ($Cdn/bbl)	Hardisty Heavy 12º API ($Cdn/bbl)	Cromer Medium 29.3º API ($Cdn/bbl)	Natural Gas[1] AECO Gas Price ($Cdn/GJ)	Natural Gas Liquids Fob[1] Field Gate ($Cdn/BBL)	Inflation Rates[2] %/Year	Exchange Rate[3] ($US/$Cdn)
Forecast								
2005	42.00	49.60	29.40	43.50	6.45	37.20	2.00	0.830
2006	39.50	46.60	29.90	40.90	6.20	35.10	2.00	0.830
2007	37.00	43.50	27.90	38.20	6.05	33.00	2.00	0.830
2008	35.00	41.10	26.30	36.00	5.80	31.20	2.00	0.830
2009	34.50	40.50	25.90	35.50	5.70	30.80	2.00	0.830

Notes:
1. This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer. Prices are from the January 1, 2005 McDaniel Forecast Prices and Costs.
2. Inflation rates for forecasting prices and costs. The inflation rate of two percent (2%) per annum is used to forecast the annual increase in oil and gas prices, operating costs and capital costs.
3. Exchange rates used to generate the benchmark reference prices in this table.
4. NGL mix based on 45% propane, 35% butane and 20% natural gasolines.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Trust's reserves are evaluated by GLJ.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Oil and Gas Properties

A summary description of the Trust's major producing and exploration properties associated with the Prime West Properties are set out below. References to gross volumes refer to total production. References to net volumes refer to the Trust's working interest share before the deduction of royalties payable to others.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Trust has a working interest in by way of the Prime West Properties:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing[3]		Producing		Non-Producing	
	Gross[1]	Net[2]	Gross	Net	Gross	Net	Gross	Net
Alberta	86	62.6	36	22.5	17	13.2	1	0.05
Saskatchewan	361	70.6	91	30.8	1	1	2	2
Total	447	133.2	127	53.3	18	14.2	3	2.05

Notes:

1. "Gross" wells means the number of wells in which the Trust has a working interest.
2. "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Trust's percentage working interest therein.
3. Non-producing includes wells shut-in for economic reasons, wells not capable of production and wells used for disposal of water.

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which we have an interest. The Trust does not have any properties that are unproductive at this time.

The following table sets out the undeveloped land holdings of the Prime West Properties as at December 31, 2004.

	Undeveloped Acres	
	Gross	Net
British Columbia	0	0
Alberta	18,732	11,117
Saskatchewan	5,174	4,615
Total	23,906	15,732

Additional Information Concerning Abandonment and Reclamation Costs

The Trust typically estimates well abandonment costs area by area. Such costs are included in the PrimeWest Reserve Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the PrimeWest Reserve Report for 110 net wells under the proved producing reserves category is estimated

$1,924,000 discounted at 10%, of which a total of approximately $710,000 is estimated to be incurred in 2005, 2006 and 2007. (This estimate does not include expected reclamation costs for surface leases). Expected future abandonment costs related to facilities are expected to match the salvage value recovery.

The Trust typically estimates that the additional reclamation costs associated with both active and inactive surface leases and wells not captured in the PrimeWest Reserve Report is $1,278,864 discounted at 10%.

Production History, Prices Received and Capital Expenditures

The following table indicates the average daily production of the Prime West Properties from important fields for the year ended 2005. The production estimate is taken from the proven developed producing reserves forecast:

	Light and Medium Crude Oil & NGL's	Heavy Oil	Gas	BOE
	(Bbls/d)	(Bbls/d)	(Mcf/d)	(BOE/d)
Grand Forks	0	450	705	568
SW Saskatchewan	296	0	288	344
Eagle Lake	93	0	35	99
Manyberries	8	0	1	8
	398	450	1,029	1,020

b. ENERGY SERVICES OPERATIONS

The June 30, 2004 acquisition of 90% of the Cascade Services Partnership ("Cascade") provided a strong entry into the energy services industry. Cascade provides vacuum truck, steaming and hydro-vac services to the energy, utility, and construction industries in Northeast British Columbia. The transaction was effected by way of a partnership structure whereby Cascade founder Ken Wagner retained a 10% partnership interest and remained with the Cascade Services Partnership as President and Chief Operating Officer. Mr. Wagner is responsible for all aspects of the day to day operations of the business. Aggregate consideration for this acquisition was approximately $5.8 million and was comprised of $3.8 million cash and the issuance of 266,667 Trust Units to the shareholders of Cascade at a deemed price of $7.50 per unit.

On July 15, 2004, the Trust, expanded its Energy Services business unit with the purchase of Indy Oilfield Services for $265,961. This acquisition provided the platform to expand the Trust/Cascade's hydro-vac, steaming and vacuum truck business into the Grande Prairie area of Northwest Alberta. In addition, eight hydro-vac and steaming trucks were purchased.

Subsequent to the year end, effective January 19, 2005, the Trust acquired Eagle Oilfield Services Inc. ("Eagle Oilfield") for an aggregate purchase price of $800,000 less assumed debt and working capital of approximately $150,000. Eagle Oilfield is now part of Cascade Services Partnership. Eagle Oilfield provides steaming, vacuum and pressure truck services in the Spirit River area outside Grande Prairie, Alberta.

With the completion of this acquisition, the Energy Services division has a total of 32 steaming, vacuum and pressure trucks in operation in northeast British Columbia and northwest Alberta.

II. FINANCIAL SERVICES BUSINESS UNIT REVIEW

At December 31, 2004 the Trust's financial services business unit, Avenir Financial Services Acquisition Corp. consisted of:

i. Financial Services Contracts

In January 2003, Avenir Financial acquired a financial services contract with an affiliate of a financial services provider, RentCash Inc. ("RentCash"), to provide funding of $600,000 for a cash advance company. RentCash provides cash advance, cheque cashing and payday loan services. The Trust has expanded its business with RentCash and has entered into additional contracts that totalled $8.9 million by the end of December 2004.

Each contract has terms as outlined below:

- A ten year life;
- The loan's recallable in 30 days at the Trust's option;
- A payment of a fixed fee per amount provided per day at a rate of $0.07 per $100 loaned per day; and
- Collateralization of the loan by the end user.

Subsequent to the year end the Trust entered into an additional $1.25 million contract and expects to add additional financial services contracts in 2005. Rentcash is a growing company and currently has over 140 Cash Stores and over 55 Insta-rent stores. The Trust expects to continue a relationship with Rentcash in the future as they grow.

ii. Subordinated Debenture

The Trust entered into respective three and four year debentures with RentCash and Pacrim Hospitality Inc. ("Pacrim") respectively. The debentures financed expansions in the respective companies and provide the Trust with 16% and 14% plus profit sharing returns.

Proposed Acquisition of Elbow River Resources Ltd.

Subsequent to year end, on February 6, 2005, the Trust announced that it had entered into an agreement to acquire Elbow River Resources Ltd. ("Elbow River"), a wholesale broker, transporter and supplier of butane to major refineries and propane to major retailers in the United States, Canada and Mexico. The proposed consideration is $57.8 million, consisting of $51.8 million cash and $6 million in the form of escrowed Trust Units, subject to normal course purchase adjustments. Elbow River, established in 1984, is considered to be one of the largest wholesale brokers in Canada and United States in providing brokerage, marketing, logistics, transportation, storage and risk management services to the natural gas liquids market. They currently transact over 12,000 boe per day of liquids sales with approximately 160 customers and suppliers.

The team at Elbow River will operate separately under the Trust's umbrella of companies. All key employees are remaining on staff and have been incentivized to meet specific EBITDA performance targets over the next three years. The acquisition, expected to close on or about April 1, 2005, expands Avenir's Financial Services business unit and continues a diversification strategy.

The suppliers and purchasers of Elbow River are generally the major oil and gas and chemical companies in Canada and the United States. Elbow River takes title of the product, arranges transportation and delivery, mainly by rail tank cars, with Elbow River paying for product and transportation. Product prices are normally determined by the spot market price. Elbow River has minimal product risk as the delivery price is generally fixed at the time that Elbow River takes title.

III. REAL ESTATE BUSINESS UNIT REVIEW

On March 31, 2004 the Trust closed its first real estate agreement when the Trust would acquired Western Spirit under a plan of arrangement. Western Spirit was a public real estate investment company with a portfolio consisting of five properties with approximately 433,000 square feet of leasable area. The properties are located in Toronto, London (Ontario), Calgary and Edmonton. Shareholders of Western Spirit received $3 million in cash and approximately 332,500 trust units of Avenir. The Trust also assumed all of Western Spirit's outstanding debt, including mortgages, of approximately $12.4 million. The Trust also issued to each Western Spirit shareholder one performance right for each Western Spirit share, each right entitling the holder to acquire 0.003333 of a trust unit, for no additional consideration, provided that, at any time on or prior to January 21, 2005, certain leasing conditions were met; however, the conditions were not met and the rights expired. A management company, Tonko Realty Advisors, administers the day to day operations of the Trust's real estate business unit.

The Trust's acquisition of Western Spirit Investments Ltd. was the founding corner stone to the real estate business unit. The Trust acquired five properties with long life leases including triple net fees (all costs are paid by the leasee including property management fees). In October 2004 the Trust approved a $1,900,000 expansion on a building in London, Ontario when the current tenant needed to increase lease space. This added 29,343 square feet to the building. The expansion was substantially completed on February 3, 2005, and includes a 10 year triple net fee lease at an approximate 9.59% cap rate. As at December 31, 2004 $1,710,000 of costs associated with this expansion have been reflected in the Trust's consolidated financial statements as an increase in the property and equipment and increased accounts payable and accrued liabilities.

Subsequent to the year end December 31, 2004 the Trust sold a warehouse building in Calgary Alberta. The building was sold for approximately 18% more than the purchase price of March 2004. On February 1, 2005 the Trust purchased an additional property, a fully leased shopping plaza in Fort Saskatchewan, Alberta, which totals 16,000 square feet, for total cash consideration of approximately $3.1 million. Currently the Real Estate business unit has over 400,000 square feet of commercial properties located in Toronto and London, Ontario and Edmonton and Calgary, Alberta of which 93% is currently leased.

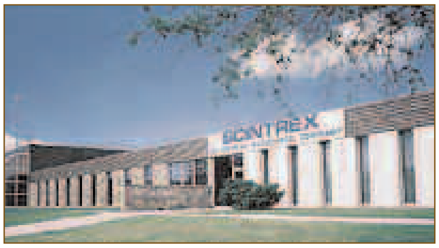
A description of the properties follows:

2305 - 84th Avenue, Edmonton, Alberta

The building was constructed for Canada Dry Bottling Co. in 1979, and was updated in 1995. This large warehouse and office facility is on a 4.57 acre parcel located in the Sherwood Industrial subdivision and can service Edmonton's industrial sector. It backs onto and has exposure to the Sherwood Park Freeway. The property's 90,800 square feet are fully leased to a manufacturer and distributor of packaging materials.

6732 - 8th Street NE, Calgary, Alberta

This research and manufacturing facility, constructed in 1991, is in the Deerfoot industrial area in northeast Calgary, immediately adjacent to the Calgary International Airport. Built in 1991 by Novatel, this facility comprises approximately 119,600 square feet resting on 9.65 acres, resulting in site coverage of 26%. It enjoys convenient access to Deerfoot Trail, and is partially leased to two international tenants.



222 Snidercroft Road, Vaughan, Ontario

This office and manufacturing facility is located in Greater Toronto's 600 million square foot industrial market, backing onto Highway 407 in a well-established business park in Vaughan. Built in two stages (1970 and 1980) for the present tenant, this renovated facility comprises approximately 71,000 square feet resting on 4.0 acres, with site coverage of only 29%. The Trust owns a 50% interest in this property.

1800 Huron Street, London, Ontario

This manufacturing/warehouse facility sits adjacent to London International Airport in the northeast industrial area of London, Ontario. The tenant is a large automotive parts manufacturer. Built in 1989, the building is fully air-conditioned and comprises approximately 112,000 square feet on 12.65 acres.

Station Crossing, Fort Saskatchewan, Alberta

Fort Saskatchewan is 30 kilometres from downtown Edmonton. This shopping plaza is located strategically at the intersection of 99th Avenue (Main Street) and 100th Street in the downtown area of Fort Saskatchewan. The centre is approximately four years old and has generous parking of approximately 107 stalls and convenient access. It sits adjacent to a recently expanded and upgraded Sobeys Grocery store and comprises 16,000 square feet.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2004 and the management discussion and analysis thereto. This management discussion and analysis relates to events up to March 29, 2005.

Except for historical financial information contained herein, the matters discussed in this document may be considered forward-looking statements. Such statements include declarations regarding management's intent, belief or current expectations. Prospective investors are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties; actual results could differ materially from those indicated by such forward-looking statements. Among the important factors that could cause actual results to differ materially from those indicated by such forward-looking statements are: (i) that the information is of a preliminary nature and may be subject to further adjustment, (ii) the possible unavailability of financing, (iii) risks related to the exploration and development of oil and gas properties, (iv) the impact of price fluctuations and the demand and pricing for oil and natural gas, (v) the seasonal nature of the business, (vi) start-up risks, (vii) general operating risks, (viii) dependence on third parties, (ix) changes in government regulation, (x) the effects of competition, (xi) dependence on senior management, (xii) financial condition of real estate tenants and financial services counterparts, (xiii) impact of the Canadian economic conditions or the demand for real estate leasing opportunities, and (xiv) fluctuations in currency exchange rates and interest rates.

Cash flow from operations, cash flow per unit, net back and working capital (net debt) are not recognized measures under Canadian generally accepted accounting principles (GAAP). Cash flow from operations is calculated by taking net income and adding back non-cash balances such as depletion, depreciation and amortization, asset retirement obligation accretion, gain on sale of investments, compensation expense, unrealized loss on financial instruments and unsuccessful acquisition and re-organizational costs. Working capital (net debt) is calculated by taking current assets less current liabilities not including current portion of mortgages (upon mortgage maturity it is the Trust's intention to renew the mortgages on a long term basis at or below current rates) and long-term debt. Management believes that these measures are useful supplemental measures to analyze operating performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments. The Trust's method of calculating these measures may differ from other issuers, and accordingly, they may not be comparable to measures used by other issuers. Investors should be cautioned that "Cash Flow From Operations" and "Cash Flow From Operations Per Unit" should not be construed as an alternative to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Distribution Payout Ratio is calculated by dividing the Distributions by the Cash Flow From Operations.

The Trust's strategy is comprised of having three distinct business units: Energy (comprised of oil & gas production and energy services), Financial Services and Real Estate. These three units combine the stability of cash flows from both real estate and financial services with a more variable higher return cash flow stream from the energy sector.

Significant Events for the Year Ended December 31, 2004

- **March 2004 Western Spirit Investments Ltd. ("Western Spirit") Acquisition**

  On March 31, 2004 the Trust closed its first real estate agreement pursuant to which the Trust would acquire Western Spirit under a plan of arrangement. Western Spirit was a public real estate investment company with a portfolio consisting of five properties with approximately 433,000 square feet of leasable area. The properties are located in Toronto, London (Ontario), Calgary and Edmonton. Through this transaction, shareholders of Western Spirit received $3 million in cash and approximately 332,500 trust units of Avenir. The Trust also assumed all of Western Spirit's outstanding debt, including mortgages, of approximately $12.4 million as at March 31, 2004.

- **June 2004 Trust Unit Consolidation**

  On June 10, 2004 the Trust consolidated its stock on a 15 to 1 basis. The consolidation was approved by unit holders at the Annual and Special Meeting of unit holders. The benefits of the consolidation included the ability of the Trust to proceed with the listing on the senior TSX exchange, be more attractive to institutional investors, be comparable price-wise to other Trusts and be able to meet margin requirements for retail clients. The Trust began trading on a consolidated basis on Monday June 14, 2004 and applied for approval to trade on the TSX.

- **June 2004 Close of Prospectus Offering**

  On June 28, 2004 the Trust closed on a public offering, through a syndicate of agents led by First Associates Investments Inc. and included Canaccord Capital Corporation, Raymond James Ltd., Acumen Capital Finance Partners Ltd. and GMP Securities Ltd. The financing was completed a prospectus for gross proceeds of approximately $28.75 million consisting of 3,833,300 trust units at a price of $7.50 per unit.

- **June 2004 Energy Services Acquisition**

  On June 30, 2004, the Trust acquired 90% of Cascade Services Partnership ("Cascade"), which provides vacuum truck, steaming and hydro-vac services to the energy, utility and construction industries in Northeast British Columbia. The transaction was effected by way of a partnership structure whereby Cascade founder Ken Wagner retained a 10% partnership interest and remains with the Cascade Services Partnership as President and Chief Operating Officer. Mr. Wagner is responsible for all aspects of the day to day operations of the Partnership's business. The acquisition of this energy services business provides the Trust with further diversification within the portfolio of energy assets and was accretive to the Trust's cash flow.

  In addition, on July 15, 2004, the Trust purchased Indy Oilfield Services for approximately $265,961. The business focus of Indy is also vacuum truck, steaming and hydro-vac services, with their operations area being Grande Prairie area of Northwest Alberta.

- **June 2004 Oil & Gas Property Acquisitions**

  On June 30, 2004, two oil and gas property acquisitions were completed in two of its core areas, Northeast Alberta and Southern Alberta. The acquisitions totalled $9.9 million and adds approximately 340 boe per day (82% gas and 18% light oil).

- **July 2004 Financial Services Debenture Contracts**

  On July 15, 2004, the Trust entered into a $1 million debenture agreement with Rentcash Inc. The $1 million debenture brought the total amount of debentures outstanding with Rentcash to $3 million. As per the previous debenture agreement, the new debenture yields a monthly coupon equivalent to a 12% annualized yield plus associated fees of 4% per year.

  On July 19, 2004, the Trust entered into a $500,000 debenture agreement with a new company, Pacrim Hospitality Services ("PHS"). Terms of the debenture include a 14% annualized coupon paid monthly and a 20% net profit interest in four properties managed by PHS. The debenture will provide funding in the building of four Super 8 Motels in Eastern Canada.

- **July 2004 TSX Listing Approval ("AVF.UN")**

  On July 26, 2004 the Trust received TSX listing approval and began trading on the senior exchange under the symbol AVF.UN.

- **August 2004 Increase in Distributions**

  On August 19, 2004, the Trust announced that the cash distribution would increased 10% from $0.08745 per unit to $0.09625 per Trust Unit for its monthly distributions. The recently concluded oil and gas and energy services acquisitions, the new financial services contracts and continued high commodity prices allowed the Trust the opportunity to increase distributions.

- **September 2004 Oil & Gas Acquisition**

  On September 30, 2004, the Trust acquired the shares of a private oil and gas company, from Lightning Energy Ltd. The $32.7 million acquisition (plus related costs and fees), with approximately 1,000 boe per day.

- **November 2004 Close of Prospectus Financing**

  On October 13, 2004 the Trust entered into an agreement with a syndicate of agents, co-led by Raymond James Ltd. and GMP Securities Ltd., in connection with a "best efforts" public offering of Trust Units by way of a prospectus for minimum proceeds of $25 million and maximum proceeds of $35 million and the over-allotment of 15%. The offering was completed on November 15, 2004 with total Trust Unit of 4,472,221 issued, including the exercise of an over-allotment option, at a price of $9.00 per Trust Unit for gross proceeds of approximately $40.25 million.

- **January to December 2004 Financial Services Contracts**

  During the year ended December 31, 2004 the Trust completed a number of financial services contracts with its cheque cashing partner, an affiliate of RentCash Inc. ("RentCash"). The total value of the contracts outstanding at December 31, 2004 was $8.9 million. The contracts have identical terms to the previous cheque cashing contracts which include the payment of $0.07 per $100 loaned per day, representing an approximate 25% annualized yield. The term of the loan is 10 years recallable on 30 days notice.

- **December 2004 Increase in Distributions**

  On December 16, 2004, the Trust increased its monthly distributions by 10% from $0.09625 per unit to $0.106 per Trust Unit beginning with the December distribution, payable January 17, 2005. The recently concluded oil and gas acquisition and continued high commodity prices allowed the Trust to increase distributions again.

- **December 2004 Oil and Gas Acquisition**

  On December 17, 2004 Avenir closed the acquisition of various properties from PrimeWest Energy Inc. and PrimeWest Gas Corp. ("PrimeWest Properties") for $30.0 million less adjustments. The acquisition provided Avenir with approximately 1,020 boe per day of production and long life reserves in its core areas of southern Alberta and southwest Saskatchewan.

Subsequent to the Year Ended December 31, 2004

- **January 2005 Proposed Oil & Gas Acquisition**

  On March 28, 2005 the Trust announced that 91.38% of the issued and outstanding common shares of Val Vista Energy Ltd. ("Val Vista") have been tendered to the offer dated February 15, 2005 ("Offer") to purchase all of the issued and outstanding Val Vista shares. The Trust will proceed to take up and pay for all of the Val Vista shares deposited under the Offer. The Trust will also proceed to acquire all of the remaining outstanding Val Vista shares pursuant to the compulsory acquisition provisions of the Business Corporations Act. The consideration given to the Val Vista shareholders will be a combination of cash and Trust Units. The cash portion has a maximum of $12,666,600 and the maximum number of Trust Units to be issued is 1,183,795

- **January 2005 Financial Services Contract**

  On January 28, 2005 the Trust completed an additional financial services contract for $1,250,000 with its cheque cashing partner, an affiliate of RentCash. The contract has identical terms to the previous cheque cashing contracts as mentioned above. The Trust has funded a total of $10.15 million in cheque cashing contracts.

- **February 2005 Proposed Elbow River Resources Ltd. ("Elbow River") Acquisition**

  On February 6, 2005, the Trust entered into the Elbow River Acquisition Agreement whereby the Trust, will acquire all of the assets and business of Elbow River for consideration of approximately $57.8 million consisting of $51.8 million cash and $6 million in the form of Trust Units, subject to normal course purchase adjustments. Elbow River's primary business is that of a wholesale broker, transporter and supplier of butane to major refineries and propane to major retailers in the United States, Canada and Mexico. Butane is mainly used in the refining process for blending with gasoline. Propane is mainly used for heating fuel in areas where natural gas is not available. Elbow River is also involved in transporting ethanol and natural gasoline, which are also components of the refining process. Elbow River has minimal product risk as the delivery price is generally fixed at the time Elbow River takes title. The acquisition is expected to close on or about April 1, 2005.

- **March 2005 Close of Prospectus Financing**

  On March 21, 2005 the Trust closed a financing at $10.90 per unit with a syndicate of agents, co-led by Raymond James Ltd. and GMP Securities Ltd. Including the over-allotment of 15%, 11,605,504 total units were issued for total proceeds of $126,499,994. The proceeds of the offering will be used to:

  - pay down the Trust's current credit facility (with respect to the PrimeWest Properties);
  - fund the cash portion of the Val Vista acquisition;
  - fund the Elbow River transaction, and
  - fund continued growth and development.

Selected Annual Information

	Year Ended December 31 (1)			
	2004	2003	2002	2001
(thousand of dollars except per share amounts)	$	$	$	$
Revenue – oil and gas (net of royalties)	14,547	3,791	–	–
Total net revenue	21,907	4,451	187	2
Cash flow from operations	10,579	2,363	(71)	(162)
Per unit basic	1.86	1.28	(0.01)	(0.03)
Net income (loss)	4,014	447	(71)	(162)
Per share basic	0.71	0.24	(0.01)	(0.03)
Total net debt incl. working capital & mortgages	(44,769)	4,274	237	(102)
Unitholders' equity	81,143	14,788	837	(102)
Total assets	155,315	22,431	2,028	2
Total net capital expenditures	98,715	16,424	–	–

Note: (1) As the Trust acquired a substantial portion of its business operations on January 16, 2003 through the acquisition of 928719 Alberta Ltd. ("928719"), the summary financial information presented above compares that of the Trust for periods after January 16, 2003 against that of 928719 for periods prior to January 16, 2003.

Selected 2004 Quarterly Information

(thousand of dollars except per share amounts)	December 31		September 30		June 30		March 31	
	2004	2003	2004	2003	2004	2003	2004	2003
Total Net Revenue	11,614	1,730	5,328	946	2,811	931	2,154	848
Net Income (loss)	2,955	(73)	781	177	(145)	60	423	282
Net Income (loss) per Unit basic	0.31	(0.03)	0.11	0.11	(0.04)	0.04	0.15	0.20
Cashflow from Operations	4,991	853	2,806	532	1,439	455	1,318	522
Total Assets	155,315	22,430	109,945	19,620	66,771	12,105	44,888	10,501
Distributions	3,053	726	2,016	516	847	358	755	254
Distributions (per Unit)	0.32	0.26	0.28	0.31	0.26	0.24	.27	0.18

Net Income and Cash Flow

Net income for each of the Trust's business units are as follows:

	For the three months ended		For the Year ended	
	December 31, 2004 $	December 31, 2003 $	December 31, 2004 $	December 31, 2003 $
Net Income (loss)				
Oil and Gas	2,601,836	(152,769)	2,574,346	146,986
Financial Services	561,003	80,002	1,293,593	299,857
Real Estate	(434,935)	–	(314,072)	–
Energy Services	227,789	–	460,584	–
Consolidated Net Income	2,955,693	(72,767)	4,014,451	446,843

The net income for the year ended December 31, 2004 were $4,014,541 which is 798% over the $446,843 net income for the year ended December 31, 2003. The Trust recorded net income of $2,955,693 for the three months ended December 31, 2004 compared to a loss of $72,767 for the three months ended December 31, 2003. The three months ended December 31, 2004 net income have been positively impacted by recognition of $1,742,280 non-cash mark-to-market opportunity gain related to risk management contracts. Consistent with most oil and gas firms of the Trust's size, the Trust does not follow hedge accounting for these contracts due to onerous monitoring and regulatory requirements.

The oil and gas net income increase of $2,427,360 for the year ended December 31, 2004 versus 2003 and the $2,754,605 increase for the quarter ended December 31, 2004 versus the fourth quarter ended December 31, 2003, is a result of the various oil and gas acquisitions in 2004. The increases in net income in the financial services business unit from $80,002 in the fourth quarter of 2003 to $561,003 in the fourth quarter of 2004, as well as the increase on a year to date basis over 2003 of $993,736 are due to the additional financial services contracts and the debentures that were entered into after the remainder of 2003 and throughout 2004. The third quarter of 2004 was the first quarter with operating results for the Trust's energy services business unit as the Cascade acquisition closed on June 30, 2004. Real Estate net income was impacted by a change in accounting policy whereby a portion of the purchase price is amortized over the life of the building lease rather than the life of the building. This resulted in the real estate division having a net loss of $314,072 for the year ended December 31, 2004.

Cash flow from operations was $10,579,736 for the year ended December 31, 2004, up 349% as cash flow for the year ended December 31, 2003 was $2,362,525. The cash flow for the fourth quarter 2004 was $4,991,022 or $0.53 per unit up 485%, compared to the fourth quarter 2003 of $853,418 or $0.31 per unit. The increase in cash flow was primarily the result of the growth in the Trust's business units, including: oil and gas acquisitions made, continued high commodity prices, additional financial services contracts, and the initial inclusion of the Western Spirit real estate acquisition at the end of March 2004.

The Trust distributed $6,671,281 or $1.17 per unit for the year ended December 31, 2004 which is up 260% over the $1,853,871 or $1.01 per unit distributed for the year ended December 31, 2003. For the fourth quarter 2004 the Trust distributed $3,053,499 ($0.32 per unit), to unitholders compared to $725,892 ($0.26 per unit) for the quarter ended December 31, 2003. On August 19, 2004 the Trust announced a 10% increase in the monthly distribution beginning with the August distribution payable September 15, 2004. On December 16, 2004 the Trust announced a further 10% increase in the monthly distribution beginning with the December distribution payable January 15, 2005. The fourth quarter payout was 60% of cash flow.

Monthly cash distributions declared per Trust unit issued and outstanding were as follows:

Period covered	Date of Distribution	Per Unit $
January 1, 2004 to January 31, 2004	02/13/2004	0.08745
February 1, 2004 to February 29, 2004	03/15/2004	0.08745
March 1, 2004 to March 31, 2004	04/15/2004	0.08745
April 1, 2004 to April 30, 2004	05/14/2004	0.08745
May 1, 2004 to May 31, 2004	06/15/2004	0.08745
June 1, 2004 to June 27, 2004	07/15/2004	0.07870
June 28, 2004 to June 30, 2004	07/15/2004	0.00880
July 1, 2004 to July 31, 2004	08/16/2004	0.09625
August 1, 2004 to August 31, 2004	09/15/2004	0.09625
September 1, 2004 to December 31, 2004	10/15/2004	0.09625
October 1, 2004 to October 31, 2004	11/15/2004	0.09625
November 1, 2004 to November 30, 2004	12/15/2004	0.09625
December 1, 2004 to December 31, 2004	01/17/2005	0.10600

REVENUE

1(a). Oil & Gas Revenue and Production

For the year ended December 31, 2004, oil and gas revenue was $16,528,426 compared to $4,560,568 for the same period in 2003. Oil and gas revenues for the fourth quarter 2004 were $8,283,101, up 334% from the fourth quarter of 2003, attributable in most part to the acquisitions made in November 2003 and June 2004 and September 2004.

Production and cash flow from the oil and gas acquisition purchased at the end of the fourth quarter, December 17, 2004, will begin to be reflected in the first quarter 2005. For the year ended December 31, 2004 14 days of production have been included in the Trust's consolidated financial statements.

Transportation costs for the year ended December 31, 2004 were $264,953 versus $4,385 for the year ended December 31, 2003. Due to change in accounting policy the prior year comparative numbers were restated to reflect the separation of the transportation costs from the oil and gas revenues. The increase is a result primarily of increased natural gas production throughout 2004.

Revenue from petroleum and natural gas sales (net of royalties) for the year ended December 31, 2004 was $14,547,323 up 284% compared to $3,791,991 for the year ended December 31, 2003. For the fourth quarter 2004 revenue from petroleum and natural gas sales was $8,202,615 up from $1,558,709 in the fourth quarter of 2003. The average price received for crude oil and natural gas liquids during the year ended December 31, 2004 was

$38.53 per boe an increase versus $35.62 per boe which was received for the year ended December 31, 2003. The fourth quarter of 2004 average was $42.16 per barrel, up 31% from the fourth quarter of 2003 and $6.56 per mcf for natural gas, up 23% from the 2003 fourth quarter average of $5.34 per mcf.

Although the Trust hedges a portion of its production to add stability to its distributions, to guard against fluctuations in commodity prices and to support acquisition economics, it has been determined that its oil swap transaction does not qualify under new hedge accounting guidelines. Accordingly, the Trust recorded a hedging cost of $702,302 for the year ended December 31, 2004 and $249,027 for the fourth quarter of 2004. In addition, the accounting treatment requires the Trust to recognize an unrealized gain of $1,748,488 for the change in the mark to market position on existing contracts from September 30, 2004 to December 31, 2004 for a total net gain for the year ended December 31, 2004 of $1,159,542.

Average daily production volumes for the year ended December 31, 2004 was 1,153 boe per day up 214% over 2003 which was 367 boe per day. The fourth quarter ended December 31, 2004 averaged 2,206 boe per day, up 248%, compared to 634 boe per day in the fourth quarter of 2003. Fourth quarter 2004 production consisted of 813 bbls per day of crude oil and natural gas liquids and 8,357 mcf per day of natural gas (compared to 299 bbls per day and 2,009 mcf per day for the fourth quarter 2003, respectively). The 172% increase in oil and liquids production came mostly from acquisitions in September 2004. The 316% increase in natural gas production was the result of the natural gas asset acquisitions completed in November 2003, June, September and December 2004.

Netbacks

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
	$/BOE	$/BOE	$/BOE	$/BOE	$/BOE	$/BOE	$/BOE	$/BOE
Gross revenue after hedging	39.51	37.58	38.11	37.19	32.73	33.67	36.31	46.74
Royalties	7.67	6.58	6.12	5.07	5.99	4.96	5.81	7.62
Operating costs	7.20	7.37	8.61	6.29	7.48	7.76	8.46	9.51
Operating netback	24.64	23.63	23.38	25.83	19.26	20.95	22.04	29.61

Royalties

The Trust's royalty costs net of ARTC for the year ended December 31, 2004 were $2,875,692 compared to $764,192 for the previous year. The quarter ended December 31, 2004 was $1,557,813, up 346% over the fourth quarter 2003; however, on a boe basis, royalty costs averaged $7.67 per boe in the period, which is up 28% over the fourth quarter 2003 cost of $5.99 per boe due mostly to higher natural gas prices. Royalties averaged 18.8% in the fourth quarter of 2004 and 17.0% for the year ended December 31, 2004 compared to 17.9% for the fourth quarter 2003 and 16.4% for the year end 2003, reflecting a slightly gassier product mix in 2004.

Operating Expenses

The Trust's operating costs for the year ended December 31, 2004 were $3,089,847 or $7.32 per boe compared to $1,021,601 or $8.01 for the year ended December 31, 2003. The quarter ended December 31, 2004 had operating costs of $1,460,330, up 235% over the fourth quarter 2003 a result of increased production due to the acquisitions in June and September 2004. On a boe basis, operating costs averaged $7.20 per boe in the period, which is down 4% over the fourth quarter 2003 cost of $7.48 per boe. Fourth quarter 2004 operating costs reflect the impact of the lower operating costs associated with the September 2004 acquisition.

1(b). Energy Services Revenue

On June 30, 2004 the Trust created Cascade Energy Services Partnership ("Cascade Partnership") through the acquisition of 90% of Cascade Steaming Ltd. ("Cascade"). Cascade was the first Energy services acquisition made by the Trust so there are no comparative results for 2003. Revenue and net income for the Energy Services division, which is a six month period, totaled $3,877,905 and $1,962,221 respectively for the year ended December 31, 2004. For the fourth quarter, revenues were $2,384,593 and net operating income totaled $1,245,067. For the quarter ended September 30, 2004, revenues totaled $1,493,312 and net operating income totaled $717,154 for the period.

2. Real Estate Revenue

The revenue and net operating income respectively from the Real Estate business unit for the year ended December 31, 2004 was $2,018,475 and $1,264,533. No revenue was recorded in this business unit in the year ended December 31, 2003 as the real estate assets were brought into the Trust on March 31, 2004, through the Western Spirit acquisition.

City	% Ownership	% Leased	Square Footage
Edmonton, AB	100%	100	90,800
Fort Saskatchewan, AB	100%	100	16,000
Calgary, AB	100%	60	119,600
Vaughan, ON[1]	50%	100	71,000
London, ON	100%	100	112,000
Total			409,400

1 Note the Trust only has 50% of the Vaughan building in Ontario.

There are various mortgages with interest rates ranging from 5.75% to 8.15% (weighted average 7.5%), maturities from March 2005 to September 2006. Subsequent to the year end, the Trust renewed the March mortgage of $5,040,047 for a three year term at a rate of 4.85%. Currently the Real Estate business unit currently leases 93% of its space.

3. Financial Services Revenue

The Trust recognized revenue in the financials services business unit of $1,358,908 for the year ended December 31, 2004 up 355% over the year ended December 31, 2003 of $298,404. The revenue and net operating income for the fourth quarter 2004 was $576,090 compared to $84,204 in the fourth quarter of 2003, up 584% due to the addition of $7.7 million of cheque cashing contracts and $1.5 million in debenture agreements added throughout 2004.

Since inception the Trust had cash advance contracts, fully collateralized, with a 10-year term, recallable at the Trust's option with 30 days notice. These contracts pay a fixed fee over the life of the contract. In the fourth quarter, the Trust added $3.25 million in contracts bringing the total cash advance contracts to $8.9 million at December 31, 2004. The Trust holds a subordinated debenture of $2 million with RentCash Inc., which closed in December 2003 and an additional $1 million debenture which was added on July 15, 2004. These debentures pay a 12% annualized yield plus 4% annualized administration fees. As well in the third quarter of 2004, the Trust invested in $500,000 debenture with Pacrim Hospitality Services. Terms of this debenture include a 14% annualized coupon paid monthly and a 20% net profit interest in four properties managed by PHS.

General and Administrative Expenses

General and administrative ("G&A") expenses for the year ended December 31, 2004 were $3,342,700 (which includes corporate costs of $329,854) compared to $868,914 for the year ended December 31, 2003. During the fourth quarter 2004 G&A expenses were $1,632,460 (which includes corporate costs of $113,566), up from the fourth quarter 2003 amount of $430,460. G&A expenses on the split between the respective business units are: $1,091,792 for oil and gas, $41,414 for real estate and $499,249 for energy services. The 282% increase in G&A expenses in 2004 is the result of additional staffing costs associated with increasing the Trust's market size and diversifying its business units and regulatory reporting.

Depletion, Depreciation and Amortization

Provision for depletion, depreciation and amortization was $7,212,726 for the year ended December 31, 2004. For the fourth quarter 2004 it totaled $3,534,913, with the Trust's depletion and depreciation rate at $12.87 per boe up from the $12.64 per boe rate in the fourth quarter of 2003. The depletion rate reflects the historically high cost per boe of acquisitions in the current market, as well as increases in asset value due to the adoption of the new accounting policy relating to asset retirement obligations that was adopted in 2004.

Asset Retirement Obligations

In 2004, the Trust adopted the new CICA Handbook section 3110, Asset Retirement Obligations. This standard focuses on the recognition and measurement of liabilities related to legal obligations associated with the retirement of property, plant and equipment. 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 obligation is capitalized to the related asset and amortized into earnings over time. The new accounting policy has been applied retroactively with restatement of prior periods. As a result of the retroactive application, the comparative consolidated statements of operations and accumulated earnings/(deficit) have been restated. The effect of the change on the net income (loss) for the year ended December 31, 2003 was a decrease of $72,337 or $0.04 per unit on a basic and diluted basis, relating to additional depletion, depreciation and amortization, the asset retirement obligations accretion and a reduction in the site restoration expense as outlined below.

The following December 31, 2003 balances were restated as a result of the change:

	As previously reported $	Adjustment $	As restated $
Balance Sheet:			
Property and equipment	14,915,876	1,129,737	16,045,613
Provision for future site restoration and abandonment	567,156	(567,156)	–
Asset retirement obligation	–	1,312,965	1,312,965
Accumulated earnings/(deficit)	285,808	383,928	669,736
Statement of Operations:			
Depletion, depreciation and amortization	1,508,038	104,226	1,612,264
Site restoration	110,891	(110,891)	–
Asset retirement obligation accretion	–	79,002	79,002

Income Taxes

The Trust did not provide for income taxes, except for the future income taxes relating to the 2004 corporate acquisitions, as it expects that all taxable income will be passed to unit holders in the form of distributions.

Interest Expense

Interest expense and bank fees were $1,117,438 for the year ended December 31, 2004 up 533% over the previous year of $176,504. For the fourth quarter 2004 interest expense totaled $511,456, compared to $64,020 for the fourth quarter ended 2003. Interest expense for the fourth quarter of 2004 includes bank fees of $13,619. The majority of the interest expense was in the real estate division where the Trust had $12,133,681 in mortgages outstanding at the quarter ended December 31, 2004.

Financial Instruments

As at January 1, 2004 the fair value of all outstanding instruments was recorded on the balance sheet with an offsetting deferred financial instrument loss. The deferred financial instrument loss is recognized in net income over the life of the associated contracts. Changes in fair value after that time are recorded on the balance sheet with the associated unrealized gain or loss recorded in net income. The estimated fair value of all financial instruments is based on quoted market prices or, in their absence, fourth party market indicators and forecasts.

The following table presents a reconciliation of the risk management asset (liability) and the deferred financial instrument loss based on the year end mark-to-market analysis that was completed:

	Dec 31, 2004 $
Risk management asset (liability), January 1, 2004	(125,676)
Net Change in mark-to-market unrealized gain (loss)	1,159,542
Change in recognized loss relating to expired contracts	113,261
Risk management asset (liability), December 31, 2004	**1,147,127**
Deferred financial instrument loss, January 1, 2004	125,676
Loss recognized relating to expired contracts	113,261
Deferred financial instrument loss, December 31, 2004	**12,415**

The Trust has the following fixed price forward contracts outstanding:

- A fixed price AECO natural gas swap for the period November 1, 2004 to October 31, 2006 on 700 gigajoules ("GJ")/day of gas at a price of $7.17 Cdn/GJ
- A fixed price AECO natural gas swap for the period January 1, 2005 to March 31, 2005 on 500 GJ/day of gas at a price of $7.60 Cdn/GJ
- A fixed price AECO natural gas swap for the period November 1, 2006 to October 31, 2007 on 700 GJ/day of gas at a price of $6.64 Cdn/GJ
- A NYMEX natural gas floor for the period April 1, 2005 to October 31, 2005 on 40000 Mmbtu/Month of gas at a price of $4.50 US/Mmbtu
- A fixed price WTI swap for the period July 1, 2004 to June 30, 2005 on 100 barrels ("Bbl")/day of crude oil at a price of $27.78 US/Bbl
- A fixed price WTI swap for the period January 1, 2005 to December 31, 2006 on 200 barrels/day of crude oil at a price of $40.50 US/Bbl
- A fixed price WTI collar for the period November 1, 2004 to October 31, 2007 on 70 barrels/day of crude oil with a floor price of $38.00 US/Bbl and a ceiling price of $44.65 US/Bbl
- A fixed price WTI floor for the period December 1, 2004 to November 30, 2007 on 170 barrels/day of crude oil with a floor price of $40.00 US/Bbl

The Trust's financial instruments that are exposed to credit risk consist primarily of trade accounts receivable and financial services contracts. Although a substantial portion of trade receivables is dependant upon the strength of the Canadian oil and gas industry, management considers credit risk to be minimal. Management routinely assesses the financial strength of partners and customers, and monitors the exposure for credit losses.

With respect to derivative financial instruments, the Trust could be exposed to losses if the counter party fails to perform in accordance with the terms of the contract. This risk is managed by diversifying the portfolio among counter parties meeting certain financial criteria.

The Trust's financial services contracts are with an affiliate of RentCash and with a chain of cash advance stores. The stated return on the financial services contracts and the principal are subject to significant credit risk. The Trust has attempted to mitigate this risk by advancing amounts to various counterparties; however, some credit risk remains. Under the Trust's revenue recognition policy, fees earned on these contracts are adjusted to reflect anticipated credit losses. No credit loss provision currently exist, but a credit loss provision will be established when management deems the risk to be significant.

The Trust is exposed to interest rate fluctuations on its bank indebtedness, which is tied to Canadian bank prime rate. In addition, given the fixed fee nature and the long period to maturity of the financial services contracts, a significant change in interest rates will affect the value of these contracts.

Liquidity and Debt

As at December 31, 2004 the Trust had total net debt including working capital and mortgages of $44,768,922. This consists of the following: bank indebtedness of $31,475,000; real estate mortgages of $12,133,681; energy services long-term debt of $1,605,663 and working capital of $445,422. The bank indebtedness was primarily incurred on December 17, 2004 in order to fund the $30,000,000 oil and gas acquisition for the PrimeWest Properties.

The Trust has a combined revolving demand facility with a major Canadian bank in the amount of $38,225,000 bearing interest at prime plus one-quarter of one percent. The revolving facility is collateralized by a floating charge debenture over all of the Trust's assets. In addition, the Trust has an acquisition and development line of $5,000,000, bearing interest at bank prime plus one and one-half percent, to fund additional oil and gas acquisitions. Commencing December 31, 2004 the revolving demand loan limit is reduced monthly by $1,100,000 and by $1,200,000 commencing January 31, 2005. Subsequent to year end the Trust's loan agreement was amended to eliminate the reduction of the limit and maintain a limit of $35,925,000. The Trust also has an operating line facility with another major Canadian bank in the amount of $500,000 bearing interest at prime plus one percent. This operating line facility is available for the operations in the Trust's energy services division.

		Payments due by period		
	Total	**Less than 1 year**	**1 – 3 years**	**4 years**
Mortgages	12,133,681	5,024,920	7,108,761	–
Capital lease obligations	32,459	32,459	–	–
Long-term debt	1,605,663	693,888	911,775	–
Lease Commitments	1,667,494	375,967	1,040,376	251,151
Total Contractual Obligations	15,439,297	6,127,234	9,060,912	251,151

Deficiencies in the working capital, ongoing operations and capital expenditures, will be managed by existing cash flow from operations (at December 31, 2004 – $10,687,818) and the availability of the Trust's current revolving demand facility and proposed future financings. With the bank facility limit of $35,925,000 the current availability of the revolving demand facility at March 29, 2005 is $35,925,000.

Subsequent to the year end, the Trust renewed existing mortgages totaling $5,040,047 for a three year term at a rate of 4.85%.

Capital Expenditures

	Year Ended December 31, 2004
	$
Land	14,985
Geological and geophysical	–
Drilling	1,455,743
Production equipment and facilities	494,292
Development expenditures	1,965,020
Energy services acquisition	3,450,668
Real estate corporate acquisition	18,309,592
Property acquisitions	74,269,334
Energy services property and equipment	2,196,693
Proceeds received on property dispositions	(1,513,906)
Other assets	37,329
Net capital expenditures	98,714,730
Property and equipment December 31, 2004	120,822,688

Contractual Obligations

The contracts outstanding with respect to the physical deliveries of oil and gas as at December 31, 2004 are as follows:

- A physical fixed price sale for the period November 1, 2004 to October 31, 2005 on 700 gigajoules/day of gas at a price of $5.94/ gigajoule.
- A physical fixed price sale for the period November 1, 2004 to March 31, 2005 on 500 gigajoules/day of gas at a price of $7.18/ gigajoule.
- A physical fixed price sale for the period November 1, 2004 to October 31, 2007 on 1,050 gigajoules/day of gas at a price of $6.55/ gigajoule.

Subsequent to December 31, 2004 the Trust entered into the following physical delivery contracts:

- A physical fixed price sale for the period April 1, 2005 to October 31, 2005 on 750 gigajoules/day of gas at a price of $6.70/ gigajoule.

The Trust has the following long-term lease commitments with respect to its premises:

- A five year lease effective May 1, 2004 with a monthly payment of $9,700;
- A five year lease effective December 15, 2004 with a monthly payment of $8,166;
- A five year lease effective February 1, 2005 with a monthly payment of $9,425; and
- A two year lease effective January 1, 2005 with a monthly payment of $4,825.

The payments over the remaining terms are as follows:

	$
2005	375,967
2006	385,392
2007	327,492
2008	327,492
2009	241,726
2010	9,425
	1,667,494

Share Capital

Trust Units	Number of Units	Amount $
Balance March 31, 2004 (as previously reported)	46,490,779	18,844,454
Consolidation of Units June 10, 2004 (on a 15 for 1 basis)	3,099,336	18,844,454
Units issued for Private Placement June 28, 2004 (net of costs)	3,833,300	26,380,126
Units issued in Cascade purchase	266,667	2,000,000
Balance June 30, 2004	**7,199,303**	**47,244,580**
Trust unit issue costs	—	(6,924)
Balance September 30, 2004	**7,199,303**	**47,217,656**
Units issued for Private Placement November 15, 2004 (net of costs)	4,472,221	37,444,594
Balance December 31, 2004	**11,671,524**	**84,662,250**

For the fourth quarter ended and the year ended December 31, 2004 the Trust had weighted average trust units outstanding of 9,484,025 and 5,685,210, respectively. The diluted per unit amount was calculated assuming the exercise of outstanding in-the-money options resulting in trust units of 9,571,459 and 5,747,845 for the fourth quarter ended and the year ended December 31, 2004, respectively. As at December 31, 2004 the total units outstanding for the Trust were 11,671,524.

Related Party Transactions

During the year ended December 31, 2004, the Trust paid $106,414 (December 31, 2003 – $85,654) to Avenir Capital Corporation ("Avenir"), a significant unitholder of the Trust for rent, administration and advisory services. Included in accounts payable is $27,104 owing to Avenir relating to administration and advisory services and $202,592 owing to Avenir relating to the acquisition of certain oil and gas properties with no fixed terms of repayment and no interest.

As outlined in the original offering circular converting Onward Energy Inc. into a trust and the amalgamation with 928719 Alberta ltd., a commitment was made to the chief executive and financial officers of the Trust that they would be entitled to a combined payment of $240,000 in cash or Trust Units if the business plan of the Trust was filled out through a real estate acquisition under specific conditions. Accordingly, with the closing of the Western Spirit acquisition, the Trust has included $240,000 in accounts payable.

During the year ended December 31, 2004, the Trust paid $150,000 to a director of the Trust for consulting fees relating to financial consulting services provided.

During the year ended December 31, 2004, the Trust incurred marketing fees of $72,000 payable to a company which has a common shareholder to the Trust. Of this balance $12,000 is included in accounts payable and accrued liabilities as at December 31, 2004.

Risks and Uncertainties

The business of developing and producing oil and natural gas reserves is inherently risky. There is risk that the sale of the Trust's reserves may be delayed indefinitely due to process constraints, lack of pipeline capacity or lack of markets. The price the Trust receives for its oil and gas reserves fluctuates continuously and for the most part is beyond its control. The Trust is also subject to the risks associated with owning oil and gas properties, including environmental risks such as the pollution of air, land and water. In all areas of the Trust business, it competes against entities that have greater technical and financial resources. The Trust's growth is dependent upon external sources of financing which may not be available on acceptable terms.

The Trust mitigates these risks by contracting professional services when required. The Trust diversifies its oil and gas market portfolio among various marketers and aggregators and among a variety of contracts with respect to pricing and term. Finally, all levels of the Trust's operations are adequately insured.

The oil and gas industry is subject to numerous risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow which include: fluctuations in commodity price, exchange rates and interest rates; capital markets risk and the ability to finance future growth; and operational risks that may affect the quality and recoverability of reserves. These risks are minimized through a consistent commodity hedging program, the development of strong relationships in the finance community and maintaining a low cost structure to maximize cash flow and profitability.

The Trust's existing Financial Services Contracts are with affiliates of a financial services provider and with a chain of cash advance stores. The stated return on the Financial Services Contracts is subject to a degree of credit risk and risk of not realizing on collateral in the event of default. The Trust is afforded full collateral on a customer's pay cheque or other security on the transaction entered into by the cash advance stores. As each transaction is generally between $100 and $300, the impact of default on any one transaction is quite small when spread over a number of customers. As with respect to all financial instruments, the Trust could be exposed to losses if a counter party fails to perform in accordance with the terms of the contracts.

With respect to the Trust's real estate investments, profitability is impacted by interest rates as the interest expense is a significant cost of these investments. The Trust looks to reduce this risk by extending the maturity of its mortgages and limiting the use of floating rates to minimize exposure to fluctuations in rates. The Trust looks to reduce operating and leasing risks through staggered lease maturities, avoiding dependence on any one tenant, and by ensuring a considerable portion of its revenue is earned from established tenants.

Sensitivities

The following table shows the estimated sensitivity of 2005 cash flows to changes in pricing, interest and volume based on December 31, 2004 year end exit production rate of 2900 boe per day with debt and hedges in place at that time:

	$	Change	Per unit
Pricing			
WTI (+US$1.00) Oil	300,000	2%	$0.027
AECO (+Cdn$0.25) Gas	270,000	2%	$0.023
Interest (+/-1.0%)	300,000	2%	$0.027
Volume			
Oil & Natural Gas Liquids (+100 boepd)	710,000	5%	$0.061
Natural Gas (+1.0 mmcfd)	1,250,000	8%	$0.107

Critical Accounting Estimates

The MD&A is based on the Trust's consolidated financial statements, which have been prepared in accordance with Canadian GAAP. The application of Canadian GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The Trust bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

The following is a discussion of the critical accounting estimates that are inherent in the preparation of the Trust's consolidated financial statements and notes thereto.

Reserve Estimates

Estimates of the Trust's reserves in its consolidated financial statements are prepared in accordance with guidelines established by NI 51-101. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

The Trust's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions such as projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate.

The present value of future net revenues should not be assumed to be the current market value of the Trust's estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization.

A downward revision in the reserve estimate could result in a higher depletion, depreciation and amortization ("DD&A") charge to earnings (see depletion and depreciation below). In addition, it the net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment below), the excess must be written off as an expense charged against earnings.

Asset Retirement Obligations

The asset retirement obligation provision recorded in the consolidated financial statements is based on an estimate for total costs for future restoration and abandonment of the Trust's petroleum and natural gas properties, as well as estimates of when these costs will occur. These estimates are based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology and political and regulatory environments.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired and was a result of various acquisitions, is assessed by the Trust for impairment at least annually. Goodwill was allocated to the business unit at the time of the acquisition based on the respective book values compared to fair values. If it is determined that the fair value of the assets and liabilities of the business units is less than the book value of the business unit at the time of assessment, an impairment amount is determined by deducting fair value from the book value and applying it against the book balance of goodwill. The offset is charges to the consolidated statement of operations as additional DD&A.

Income Taxes

The Trust's operating entity is a taxable entity under the Tax Act and is taxable only on income that is not distributed or distributable to Unit holders. As the Trust distributes all of its taxable income to the Unit holders pursuant to the Trust Indenture and meets the requirements of the Tax Act applicable to the Trust, no provisions for income taxes have been made.

Recent Accounting Pronouncements and the Impact on the Trust

Hedging Relationships

CICA recently issued Accounting Guideline 13 – Hedging Relationships, which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline establishes conditions for applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. We enter into financial instruments to manage our commodity price risk and only apply hedge accounting where it is appropriate to do so under the new standard.

Transportation costs

In accordance with new accounting standards, revenue is not reported before deduction of transportation costs. The change in classification has no impact on net earnings, earnings per unit or working capital. The comparative figures have been restated to conform to the presentation adopted for the current period.

Full Cost Accounting

CICA issued Accounting Guideline 16, "Oil & Gas Accounting – Full Cost". The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline modifies how the ceiling test is performed, and requires that cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the costs centre would be written down to its fair value. Fair value is estimated using accepted present value techniques, which incorporate risks and other uncertainties when determining expected cash flows. There is no impact on the Trust's reported financial results as a result of applying the new guideline.

For additional information on the Trust, including the Annual Information Form (AIF), please go to the company's profile on SEDAR at **www.sedar.com** or the Trust's website at **www.avenirtrust.com**.

Submitted on behalf of the Board of Directors by:

WILLIAM M. GALLACHER
President & CEO

GARY DUNDAS
Vice President Finance & CFO

AUDITORS' REPORT

To the Unitholders of

Avenir Operating Corp.

We have audited the consolidated balance sheets of Avenir Diversified Income Trust as at December 31, 2004 and 2003 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, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

ERNST & YOUNG LLP
Chartered Accountants

Calgary, Alberta
March 29, 2005

CONSOLIDATED BALANCE SHEETS

As at December 31,	2004 $	2003 $
		(restated – note 3)
ASSETS [note 15]		
Current		
Cash	327,217	256,872
Restricted cash [notes 9 and 16]	160,227	—
Accounts receivable and prepaid expenses	9,847,972	1,799,803
Risk management asset [note 23]	1,147,127	—
	11,482,543	2,056,675
Property and equipment [notes 4, 5, 11, 16 and 18]	120,822,688	16,045,613
Investment in financial services contracts [note 14]	12,472,055	3,241,963
Deferred charges [note 13]	442,358	—
Goodwill and other intangibles [notes 4, 5, 8 and 12]	10,095,209	1,086,729
	155,314,853	22,430,980
LIABILITIES AND UNITHOLDERS' EQUITY		
Current		
Bank indebtedness [note 15]	31,475,000	4,505,000
Accounts payable and accrued liabilities [note 24]	9,470,009	1,489,755
Distributions payable [note 29]	1,237,182	241,964
Deferred revenue	230,805	—
Due to non-controlling interest owner [note 26]	66,667	—
Current portion of capital lease obligations [note 17]	32,459	61,162
Current portion of long-term debt [note 18]	693,888	—
Current portion of mortgages [note 16]	5,024,920	—
	48,230,930	6,297,881
Capital lease obligations	—	32,459
Mortgages [note 16]	7,108,761	—
Long-term debt [note 18]	911,775	—
Asset retirement obligation [note 19]	8,033,301	1,312,965
Future income taxes [note 27]	9,626,982	—
Non-controlling interest [note 26]	259,755	—
Commitments [note 25]		
Unitholders' equity		
Unitholder capital [note 20]	84,662,250	15,851,942
Contributed surplus [note 20]	322,064	119,868
Accumulated earnings	4,684,187	669,736
Accumulated cash distributions	(8,525,152)	(1,853,871)
	81,143,349	14,787,675
	155,314,853	22,430,980

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Director

Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED EARNINGS

For the year ended December 31,	2004 $	2003 $
		(restated – note 3)
REVENUE		
Oil and gas revenue	16,528,426	4,560,568
Oil and gas transportation costs	(264,953)	(4,385)
Royalties, net of ARTC	(2,875,692)	(764,192)
Unrealized gain on financial instruments [note 23]	1,159,542	—
	14,547,323	3,791,991
Real estate revenue	2,018,475	—
Energy services revenue	3,877,905	—
Financial services revenue	1,358,908	298,404
Investment revenue	—	226,975
Interest and other revenue	104,705	5,154
Gain on sale of short-term investments	—	128,509
	21,907,316	4,451,033
EXPENSES		
Oil and gas operating	3,089,847	1,021,601
Real estate operating	753,942	—
Energy services operating	1,915,684	—
Financial services operating	12,000	—
General and administrative [notes 21 and 24]	3,342,700	868,914
Interest and bank fees	1,117,438	176,504
Capital taxes	138,598	12,848
Depletion, depreciation and amortization	7,212,726	1,612,264
Asset retirement obligation accretion [note 19]	241,948	79,002
Unsuccessful acquisition and re-organizational costs	—	233,057
	17,824,883	4,004,190
Income before income tax and non-controlling interest	4,082,433	446,843
Income tax expense	—	—
Net income before non-controlling interest	4,082,433	446,843
Non-controlling interest [note 26]	(67,982)	—
Net income for the year	4,014,451	446,843
Accumulated earnings (deficit), beginning of year	669,736	(233,372)
Retroactive application of change in accounting policy [note 3]	—	456,265
Accumulated earnings, beginning of year, as restated	669,736	222,893
Accumulated earnings, end of year	4,684,187	669,736
Net income per unit [note 20]		
Basic	0.71	0.24
Diluted	0.70	0.24

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the year ended December 31,	2004 $	2003 $
		(restated – note 3)
OPERATING ACTIVITIES		
Net income for the year	4,014,451	446,843
Add (deduct) non-cash items:		
Depletion, depreciation and amortization	7,212,726	1,612,264
Gain on sale of short-term investments	—	(128,509)
Non-cash general and administrative [note 21]	202,196	119,868
Asset retirement obligation accretion	241,923	79,002
Unrealized gain on financial instruments	(1,159,542)	—
Non-controlling interest	67,982	—
Unsuccessful acquisition and re-organizational costs	—	233,057
Funds from operations	10,579,736	2,362,525
Change in non-cash working capital	(2,888,095)	(506,904)
Cash provided by operating activities	7,691,641	1,588,621
FINANCING ACTIVITIES		
Issue of trust units, net of issue costs	63,817,796	14,599,000
Distributions to unitholders	(5,676,063)	(1,611,907)
Increase in bank indebtedness	26,970,000	3,642,141
Repayment of mortgages	(313,649)	—
Repayments of capital lease obligations	(61,162)	(14,544)
Increase in long-term debt	408,645	—
Change in non-cash working capital	—	(2,386)
Cash provided by financing activities	85,145,567	13,612,304
INVESTING ACTIVITIES		
Purchase of Onward Energy Inc. [note 8]	—	(1,643,458)
Purchase of Outback Energy Inc. [note 7]	—	(141,592)
Purchase of 728409 Alberta Ltd. [note 6]	—	(1,319,863)
Purchase of Western Spirit Investments Ltd. [note 5]	(3,557,647)	—
Purchase of Cascade Services Partnership [note 4]	(3,492,451)	—
Purchase of Indy Oilfield Ltd. [note 4]	(265,961)	—
Oil and gas property acquisitions [note 11]	(74,269,334)	(9,480,647)
Oil and gas property disposals [note 11]	1,513,906	65,000
Oil and gas development expenditures	(1,965,020)	(730,886)
Purchase of energy services assets	(2,196,693)	—
Purchase of other assets	(37,329)	(17,377)
Disposal of other assets	—	3,905
Purchase of financial services contracts	(9,243,520)	(2,641,963)
Sale of marketable securities	—	4,186,199
Purchase of marketable securities	—	(3,047,690)
Unsuccessful acquisition and re-organizational costs	—	(233,057)
Restricted cash [note 9]	178,723	—
Changes in non-cash working capital	568,463	(292,121)
Cash used in investing activities	(92,766,863)	(15,293,550)
Increase in cash and cash equivalents during the year	70,345	174,375
Cash and cash equivalents, beginning of year	256,872	82,497
Cash and cash equivalents, end of year	327,217	256,872
Cash interest paid	1,003,405	144,359

See accompanying notes to the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2004 and 2003

1. NATURE OF THE ORGANIZATION

Avenir Diversified Income Trust ("AVF" or the "Trust") is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created through a trust indenture dated effective September 24, 2002 between Onward Energy Inc. ("Onward") and Olympia Trust Company. Pursuant to a Plan of Arrangement (the "Arrangement") dated effective January 16, 2003 involving the Trust and Onward, Onward was converted from a corporate entity to the Trust. To facilitate this conversion, all of the common shares and options of Onward were exchanged for an aggregate of 146,289 Trust Units and $2,351,305 in cash.

In conjunction with the completion of the Arrangement, the Trust acquired all the issued and outstanding shares of a private company, 928719 Alberta Ltd. ("928719"), in exchange for an aggregate of 509,991 Trust Units. This transaction was in effect a reverse takeover as the shareholders of 928719 controlled the majority of units in the Trust after the transaction and the management and directors of 928719 have carried on the management of the Trust.

Also as part of the Arrangement, the Trust acquired all of the trust units of Avenir Operating Trust and the shares of the general partners of two newly created limited partnerships involved in oil and gas and financial services activities.

In connection with the Arrangement, the Trust also completed a private placement of an aggregate of 755,023 Trust Units at $6.00 per unit, which closed in a series of two allocations.

The beneficiaries of the Trust are the unitholders. The Trust, a public income trust trading on the TSX Venture exchange, distributes a portion of its cash flow on a monthly basis to its Unitholders. It currently carries on businesses in the areas of exploration and development of oil and gas properties in western Canada, financial services, real estate and energy services.

Cash flow is currently provided to the Trust from the oil and gas properties owned and operated by Avenir Operating Corp., the financial services income of its wholly owned subsidiary Avenir Financial Services Limited Partnership, the real estate income of its wholly owned subsidiary Avenir Real Estate Acquisition Corp. and the energy services income of its 90% interest in Cascade Services Partnership. Cash flow is paid from these corporations and partnerships to the Trust by way of net profit payments, partnership income, interest payments and principal repayments. The cash payments received by the Trust are subsequently distributed to the unitholders monthly.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Avenir Diversified Income Trust (the "Trust") have been prepared by management in accordance with Canadian generally accepted accounting principles The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies noted below.

a) Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries and partnerships. Non-controlling interest relating to the Trust's interest in Cascade Services Partnership is reported separately on these consolidated financial statements.

b) Marketable securities

Marketable securities extending beyond three months but less than a year are recorded at the lower of cost or market value. Any reduction in the carrying value of the investments and any gains or losses on ultimate disposition will be reflected in the statement of operations and accumulated earnings.

c) Property and equipment

Oil and gas properties

The Trust follows the full cost method of accounting for its oil and gas activities whereby all costs associated with the acquisition of, exploration for and development of oil and gas reserves are capitalized. Such costs include those related to lease acquisition, geological and geophysical activities, lease rentals on unproved properties, drilling both productive and non-productive wells, and equipping costs directly related to acquisition, exploration and development activities.

Proceeds from the disposal of properties are normally applied as a reduction of the costs unless crediting proceeds to the full cost pool results in a change of 20% or more in the depletion rate, in which case a gain or loss is recorded.

Depletion of oil and gas properties and depreciation of production equipment is provided using the unit of production method based on estimated proven oil and gas reserves, before royalties, as determined by the Trust's independent reservoir engineers. The relative volumes of oil and gas reserves and production are converted to a common unit of measure on the basis of relative energy content at a ratio of six (6) mmcf to one (1) barrel of oil equivalent (boe).

Costs of unproved properties and salvage values are initially excluded from the calculation of depletion. Costs of future developments are initially included in the calculation of depletion. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to depletable properties.

Furniture and computer equipment are depreciated using the declining balance method at rates of 20% and 30% respectively.

Ceiling test

The Trust calculates its ceiling test by comparing the carrying value of oil and gas property and equipment to the sum of undiscounted cash flows expected to result from the future production of gross proved reserves and the sale of unproved properties. Cash flows are based on third party quoted forward prices, adjusted for transportation and quality. Should the ceiling test result in an excess of carrying value, the Trust would then measure the amount of impairment by comparing the carrying amounts of property and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the sale of unproved properties. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess is recorded as a permanent impairment.

The carrying value of unproved properties is reviewed periodically and written down to net realizable value if impairment is determined.

Real estate properties

Real estate properties are stated at the lower of cost less accumulated amortization and net recoverable amount. Costs include the original cost of the property and related acquisition costs. Net recoverable amount represents the undiscounted estimated future net cash flow expected to be received from the ongoing use and residual worth of the properties. The Trust capitalizes all direct costs relating to real estate acquisitions including carrying costs such as professional, transaction and overhead directly attributable to these activities. The Trust amortizes the costs of its buildings using the straight-line method over their estimated useful lives ranging from approximately 30 to 40 years.

Leasing costs, including leasing concessions, are amortized on a straight-line basis over the terms of the related leases.

Energy services equipment

Energy services assets are recorded at cost. The Trust amortizes the costs of its energy services equipment using the diminishing balance method. The rates used as set out below are estimated to be sufficient to amortize the cost of the assets by the expiration of their useful lives:

Automotive equipment	30%
Heavy Automotive equipment	40%
Equipment	20%
Computer	30%
Radio	25%
Furniture and fixtures	20%

Impairment

Under Canadian Institute of Chartered Accountants (CICA)Handbook Section 3063, “Impairment of long-lived assets”, an impairment loss should be recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected from its use and anticipated disposal value. The impairment recognized is measured as the amount by which the carrying amount of the assets exceeds its fair value. Real estate properties are recorded at lower of cost less accumulated amortization. . If it is determined that the carrying amount of a real estate property exceeds the estimated future net cash flow expected to be received from the ongoing use and residual worth of the property, it is reduced to its estimated fair value. These was no financial impact relating to the implementation of CICA Handbook Section 3063.

d) Asset retirement obligations

The Trust recognizes the fair value of a liability for an asset retirement obligation related to its oil and gas activities in the period in which the asset is acquired, developed or built with a corresponding increase in the carrying value of the related long-lived asset. The fair value of the liability is determined through a review of engineering studies, industry guidelines, and management’s estimate on a site-by-site basis. The liability is subsequently adjusted for the passage of time, and is recognized as an accretion expense in the statement of operations. The increase in the carrying value of the asset is amortized using the unit of production method based upon estimated gross proven reserves as determined by independent engineers. Actual costs incurred upon settlement of the obligations are charged against the liability.

e) Financial services contracts

Financial services contracts are recorded at the lower of cost and fair market value determined using industry data at the period end.

f) Deferred charges

Development charges represent property investigation costs, which are capitalized on acquisition of properties or expensed when investigations are no longer warranted.

Costs incurred to secure new tenants are amortized over the term of the lease.

g) Joint operations

Substantially all of the Trust's oil and natural gas exploration activities are conducted jointly with others. These financial statements reflect only the Trust's proportionate interest in such activities.

h) Goodwill and other intangibles

Goodwill represents the excess of purchase price over fair value of net assets acquired and liabilities assumed. Goodwill is not subject to amortization, but is tested for impairment on an annual basis by applying a fair value based test. The amount of impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any goodwill impairment will be recognized as an expense.

Intangible assets and liabilities are recorded at cost and amortized over their estimated useful lives. Intangible assets are regularly evaluated by comparing their applicable estimated future net cash flows to the unamortized net book value of the intangible asset. Any permanent impairment would be charged to income in that period.

In connection with its real estate acquisitions the Trust allocates the purchase price to land; building; intangible assets and liabilities, such as the value of above and below market leases; the value of in-place leases; origination costs associated with in-place leases and the value of tenant relationships, if any. The value associated with tenant relationships is amortized over the expected term of the relationship. The value of above and below market leases and origination costs associated with in-place leases are recorded and amortized over the remaining term of the associated lease which range from 3.5 years to 11 years.

i) Revenue recognition

Oil and gas sales are recognized as revenue when the commodities are delivered to customers.

Income from financial services contracts and investment income is recognized on a monthly basis as earned based on the stipulations in the individual contracts and agreements.

Income from energy services is recognized as the services are rendered to its customers.

Income from properties includes rents from tenants under leases, percentage participation rents, property taxes and operating cost recoveries, lease cancellation fees, leasing concessions, parking income and incidental income. Percentage participation rent is recognized after the minimum sales level has been achieved in accordance with each lease. All other rental revenue is recognized in accordance with each lease.

Income from properties recorded in the statements of income during free rent periods represents future cash receipts and is reflected in the balance sheets in receivables and recognized in the income statements on a straight-line basis over the initial term of the lease.

The Trust accounts for stepped rents on a straight-line basis.

j) Use of estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. The amounts recorded for depletion, depreciation and amortization, and the ceiling test calculations are based on estimates of gross proven reserves, production rates, commodity prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant. These estimates are reviewed periodically and as adjustments become necessary, they are reported in earnings in the period in which they become known.

Inherent in the fair value calculation of asset retirement obligations, are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and gas property and equipment balance.

k) Unit option plan

Under the Trust's unit option plan, options to purchase trust units are granted to directors, officers, employees at current market prices. Options granted by the Trust are accounted for in accordance with the fair-value method of accounting for stock-based compensation, and as such the cost of the option is charged to net income with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value using a Black-Scholes option-pricing model (see note 21). Consideration upon exercise of the options, along with the amount recorded as contributed surplus, is recorded as an increase in unitholders' contributions.

Direct awards of units to employees and unit option awards granted to non-employees have been accounted for in accordance with the fair value method of accounting for stock based compensation. The fair value of direct awards of units is determined by the quoted market price of the Trust's units on the date of grant. To date no direct award of units have been completed.

l) Per unit amounts

The Trust utilizes the treasury stock method in determining diluted per unit amounts whereby the diluted number of units is calculated assuming that the proceeds that arise from the exercise of outstanding, in-the-money options are used to purchase units of the Trust at their average market price for the period.

m) Income taxes

The Trust, and its operating entity, are taxable entities under the Income Tax Act of Canada and are taxable only on income that is not distributed or distributable to the Unitholders. As the Trust distributes all of its taxable income to the Unitholders pursuant to the Trust Indenture and meets the requirements of the Income Tax Act of Canada applicable to the Trust, no provision for income taxes has been made in these consolidated financial statements.

Avenir Operating Corp., Avenir Financial Services Acquisition Corp., Avenir Real Estate Acquisition Corp. and Avenir Energy Services Corp. ("Corporations"), subsidiaries of the Trust, are taxable Canadian corporations and are liable for tax on income that they retain. The Corporations are also subject to capital taxes in jurisdictions where such taxes apply and these taxes are deducted from distributions to Unitholders.

The Trust and the Corporations follow the liability method for calculating income taxes. Differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases are applied to tax rates in effect to calculate the future tax liability. The effect of any change in income tax rates is recognized in the period the change is substantially enacted.

n) Financial instruments

The Trust may periodically enter into derivative financial instrument contracts to manage exposures related to interest rates, foreign currency exchange rates, and oil and natural gas prices. Gains or losses on the various derivative contracts which settle via net cash payment and that meet the hedge criteria are recognized into earnings concurrent with the hedged transaction. Amounts received or paid under interest rate swaps are recognized in interest expense, while settlement amounts on commodity and foreign currency hedge contracts are recognized in earnings as the related production revenues are recorded. The Trust does not enter into financial instruments for trading or speculative purposes.

The hedging requirements as amended by Accounting Guideline 13, consist of the designation of the instrument as a hedge, the identification of the nature of the risk exposure being hedged and that there is reasonable assurance that the instrument is expected to be an effective hedge throughout its term. In addition, in the case of anticipated transactions, it is also probable that the transaction designated as being hedged will occur. The Trust assesses, both at the hedge's inception and on an ongoing basis, whether the derivative financial instruments that have been designated as hedges are highly effective in offsetting changes in fair value or cash flows of the hedged items.

Realized and unrealized gains and losses associated with hedging instruments which have been terminated or cease to be effective prior to maturity, are deferred as other current or non-current assets or liabilities on the balance sheet, as appropriate, and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedge item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

For transactions that do not qualify for hedge accounting, the Trust 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 statements of operations.

The Trust has currently elected not to apply hedge accounting to its hedging relationships.

3. CHANGES IN ACCOUNTING POLICIES

Asset retirement obligations

The Trust has adopted the new CICA Handbook section 3110, Asset Retirement Obligations. This standard focuses on the recognition and measurement of liabilities related to legal obligations associated with the retirement of property, plant and equipment. 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 obligation is to be capitalized to the related asset and amortized into earnings over time. The new accounting policy has been applied retroactively with restatement of prior periods. As a result of the retroactive application, the comparative consolidated statements of operations and accumulated earnings have been restated. The effect of the change on the net income for the year ended December 31, 2003 was a decrease of $72,337 or $0.04/unit on a basic and diluted basis, relating to additional depletion, depreciation and amortization, the asset retirement obligations accretion and a reduction in the site restoration expense.

The following December 31, 2003 balances were restated as a result of the change:

	As previously reported $	Adjustment $	As restated $
Balance Sheet:			
Property and equipment	14,915,876	1,129,737	16,045,613
Provision for future site restoration and abandonment	567,156	(567,156)	—
Asset retirement obligation	—	1,312,965	1,312,965
Accumulated earnings	285,808	383,928	669,736
Statement of operations:			
Depletion, depreciation and amortization	1,508,038	104,226	1,612,264
Site restoration	110,891	(110,891)	—
Asset retirement obligation accretion	—	79,002	79,002

Full cost accounting

The Trust has adopted the new CICA Accounting Guideline 16, “Oil & Gas Accounting – Full Cost”. The new guideline modifies how the ceiling test is performed, and requires that cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques, which incorporate risks and other uncertainties when determining expected cash flows. There is no impact on the Trust’s reported financial results as a result of applying the new guideline.

Hedge accounting

Effective January 1, 2004, the Trust prospectively adopted the new CICA accounting guideline AcG-13 “Hedging Relationships”. Financial instruments that are not designated as hedges under the guideline are recorded on the balance sheet as either an asset or liability with the change in the fair value recognized in net earnings. The Trust has elected not to designate any of its risk management activities as accounting hedges under AcG-13, and accordingly has marked to market its financial instruments.

The impact on the Trust’s financial statements as at January 1, 2004 is the recognition of a risk management liability and a deferred financial instrument loss of $125,676. The deferred financial instrument loss is being recognized in earnings as the contracts expire. See note 23 for additional information regarding the financial instruments and risk management.

Transportation costs

In accordance with new accounting standards, revenue is reported before deduction of transportation costs and a separate line for transportation costs has been presented in the statement of operations. The change in classification has no impact on net earnings, earnings per unit or working capital. The comparative figures have been restated to conform to the presentation adopted for the current year.

4. CASCADE SERVICES PARTNERSHIP

On June 30, 2004 the Trust acquired 90% of the partnership units of Cascade Services Partnership (“Cascade Partnership”), for total consideration of $5,492,451 consisting of cash of $3,835,465 and the issuance of 266,667 Trust Units at $7.50 per unit. The Cascade Partnership was the first investment by the Trust’s new energy services business unit and is involved in providing steaming, vacuum truck and hydro vac services to the energy, utility and construction industries in Northeast British Columbia and Northwest Alberta. The Trust Units were valued based on the average fair market value of the units immediately prior to the date the acquisition was announced.

Results from operations for the Cascade Partnership are included in the Trust's consolidated financial statements from the closing date of acquisition. The transaction has been accounted for using the purchase method as follows:

	$
Calculation of purchase price:	
Cash consideration	3,835,465
Trust units issued	2,000,000
Transaction costs	219,758
Less: cash received	(562,772)
	5,492,451
Allocation of purchase price:	
Non-cash working capital	694,759
Property and equipment	2,950,193
Goodwill and other intangibles	3,004,840
Long-term debt	(903,425)
Non-controlling interest	(253,916)
	5,492,451

On July 15, 2004, Cascade Partnership acquired all the outstanding shares of Indy Oilfiled Ltd. ("Indy"), for net cash consideration of $265,961. Indy represents the second acquisition in the Trust's new energy services business unit and is involved in providing steaming, vacuum truck and hydro vac services to the energy, utility and construction industries in Northwest Alberta.

Results from operations for Indy are included in the Trust's consolidated financial statements from the closing date of acquisition. The transaction has been accounted for using the purchase method as follows:

	$
Calculation of purchase price:	
Cash consideration	322,840
Transaction costs	51,411
Less: cash received	(108,290)
	265,961
Allocation of purchase price:	
Non-cash working capital	(87,547)
Property and equipment	500,475
Goodwill and other intangibles	151,150
Long-term debt	(293,593)
Non-controlling interest	(4,524)
	265,961

5. WESTERN SPIRIT INVESTMENTS LTD.

On March 31, 2004 the Trust acquired all of the outstanding shares of Western Spirit Investments Ltd. ("Western Spirit"), a publicly traded real estate company, for consideration consisting of cash of $3,000,000 and the issuance of 332,500 Trust Units. The Trust Units were valued based on the average fair market value of the units immediately prior to the date the acquisition was announced. The Trust also issued an aggregate of 10,513,179 performance rights. Each performance right entitles the holder to acquire 0.003333 of a Trust Unit for no additional consideration, provided that, at any time on or prior to January 21, 2005 either a signed lease agreement is in place for that portion of the area in the Harris Building which is currently vacant, or the Trust sells the Harris Building for not less than $8,500,000. These rights have now expired and there was no adjustment made.

Results from operations are included in the Trust's consolidated financial statements from the closing date of acquisition. The transaction has been accounted for using the purchase method as follows:

	$
Calculation of purchase price:	
Cash consideration	3,000,000
Trust units issued	2,992,512
Transaction costs	706,873
Less: cash received	(149,226)
Less: restricted cash	(338,950)
	6,211,209
Allocation of purchase price:	
Non-cash working capital	(301,294)
Real estate properties	18,309,592
Goodwill and other intangibles	2,343,106
Deferred charges	232,179
Mortgages	(12,447,330)
Deferred revenue	(215,896)
Severance costs	(550,000)
Tenant improvement	(78,000)
Future income taxes	(1,081,148)
	6,211,209

6. 728409 ALBERTA LTD. ACQUISITION

On September 24, 2003 the Trust acquired all of the outstanding shares of 728409 Alberta Ltd. ("728409"), a private oil and gas company for consideration consisting of the issuance of 133,331 Trust units at $7.50 per unit including preliminary adjustments and cash of $1,282,829. The trust units were valued based on the average fair market value of the units immediately prior to the date the acquisition was announced.

Results from operations are included in the Trust's consolidated financial statements from the date of acquisition. The transaction has been accounted as of the closing date of the acquisition for using the purchase method as follows:

	$
Calculation of purchase price:	
Trust units issued	1,000,000
Cash consideration	1,282,829
Transaction costs estimated	131,117
Less: cash received	(94,083)
	2,319,863
Allocation of purchase price:	
Working capital	125,774
Oil and gas properties/production equipment	2,325,927
Asset retirement obligations	(23,673)
Long-term capital lease obligations	(108,165)
	2,319,863

7. OUTBACK ENERGY INC. ACQUISITION

On May 27, 2003 the Trust acquired all of the outstanding shares of Outback Energy Inc. ("Outback"), a private oil and gas company, for consideration consisting of the issuance of 155,554 Trust units. The trust units were valued based on the average fair market value of the units immediately prior to the date the acquisition was announced.

Results from operations are included in the Trust's consolidated financial statements from the date of acquisition. The transaction has been accounted as of the closing date of the acquisition using the purchase method as follows:

	$
Calculation of purchase price:	
Trust units issued	1,050,011
Transaction costs	141,592
	1,191,603
Allocation of purchase price:	
Working capital	(205,917)
Bank indebtedness	(260,000)
Oil and gas properties/production equipment	1,687,517
Asset retirement obligations	(29,997)
	1,191,603

8. ONWARD ENERGY INC. ACQUISITION

Pursuant to the Plan of Arrangement more fully described in note 1, on January 16, 2003 Onward shareholders voted to convert to an income trust through a reverse takeover with 928719. The 146,289 trust units issued were valued based on the fair market value of the net assets acquired at the date of exchange. The transaction has been accounted for as of the closing date of the acquisition using the purchase method as follows:

	$
Calculation of purchase price:	
Cash consideration	2,351,305
Trust units issued	877,749
Transaction costs	116,548
Less: cash received	(824,395)
	2,521,207
Allocation of purchase price:	
Working capital	(414,160)
Oil and gas properties/production equipment	2,285,069
Goodwill	1,086,729
Asset retirement obligations	(436,431)
	2,521,207

9. RESTRICTED CASH

Restricted cash consists primarily of deposits in money market mutual funds, for property specific tenant improvement expenditures and funding of future capital expenditures and repairs for one of the Trust's buildings.

	2004 $	2003 $
Restricted cash – tenant renewal and leasing cost fund required by mortgage agreements for the real estate properties	160,227	—
	160,227	—

10. MARKETABLE SECURITIES

On December 31, 2002, the Trust held a portfolio investment of 100,000 units in Provident Energy Trust, an oil and gas Trust. In order to lock in returns and diversify the Trusts' investment exposure, the units were sold on June 30, 2003 and a gain of $75,190 was recognized.

On July 26, 2003 the Trust purchased units of three publicly trading energy trusts. Total cost of the acquisitions was $1,088,111. On September 25, 2003, in order to partially deploy funds prior to its use for investment in long-term opportunities, the Trust purchased additional units of publicly trading energy trusts at a cost of $1,959,579. All short-term investments in units were sold during the fourth quarter of 2003 to finance activities in line with the Trust's business plan and a gain of $53,319 was recognized.

11. PROPERTY AND EQUIPMENT

2004	Cost $	Accumulated Depletion, Depreciation and Amortization $	Net Book Value $
Oil and gas properties/production equipment	102,999,990	7,250,072	95,749,918
Real estate properties	20,019,592	331,964	19,687,628
Energy services equipment	5,907,361	652,802	5,254,559
Financial services assets	15,000	—	15,000
Oil and gas assets under capital lease [note 17]	175,689	93,170	82,519
Furniture and computer equipment	50,798	17,734	33,064
	129,168,430	8,345,742	120,822,688

2003	Cost $	Accumulated Depletion, Depreciation and Amortization $	Net Book Value $
Oil and gas properties/production equipment	17,468,716	1,537,285	15,931,431
Assets under capital lease	175,689	71,482	104,207
Furniture and computer equipment	13,472	3,497	9,975
	17,657,877	1,612,264	16,045,613

a) During 2004 the Trust sold non-core oil and gas assets for total cash consideration of $1,513,906, including adjustments to date. The entire purchase price has been allocated to oil and gar properties.

b) During 2004 the Trust purchased oil and gas for total cash consideration of $41,560,044 including adjustments to date. The entire purchase price has been allocated to oil and gas properties. An additional asset retirement obligation of $3,702,531 was recorded on these acquisitions. During 2004 the Trust also purchased additional energy services equipment for total cash consideration of $2,196,693.

c) On September 30, 2004 the Trust purchased oil and gas assets through the acquisition of all of the outstanding shares of 1111578 Alberta Ltd. from an unrelated party for total cash consideration of $32,709,289, including adjustments to date. The purchase price has been allocated as follows:

	$
Allocation of purchase price:	
Oil and gas properties/production equipment	39,679,905
Goodwill	3,938,426
Asset retirement obligation	(2,363,208)
Future income tax	(8,545,834)
	32,709,289

d) Included in oil and gas properties is unproven properties of $22,262,300 which has been excluded from the calculation of depletion and depreciation (December 31, 2003 – $150,000).

e) The Trust has performed an impairment test on its oil and gas properties and equipment as of December 31, 2004 using the estimated average price for each of the next five years as determined by the Trust's independent reserve engineers adjusted for differentials specific to the Trust's reserves as follows:

Year	Oil ($US WTI/bbl)	Gas ($CDN/bbl)
2005	42.00	6.65
2006	39.50	6.40
2007	37.00	6.20
2008	35.00	5.90
2009	34.50	5.80

Each benchmark price increases by an average of 2 percent thereafter.

There was no impairment as at December 31, 2004.

f) Included in the energy services equipment is $260,000 relating to future prospects.

12. GOODWILL AND OTHER INTANGIBLES

Goodwill and other intangibles relate to the Western Spirit, Cascade Partnership, Indy and the Onward acquisitions (see notes 4, 5 and 8).

		2004	
	Cost $	Accumulated Depletion and Depreciation $	Net Book Value $
Goodwill and other intangibles	8,181,145	—	8,181,145
Intangible assets relating to real estate properties [note 5]	2,343,106	429,042	1,914,064
	10,524,251	429,042	10,095,209

		2003	
	Cost $	Accumulated Depletion and Depreciation $	Net Book Value $
Goodwill and other intangibles	1,086,729	—	1,086,729
Intangible assets relating to real estate properties [note 5]	—	—	—
	1,086,729	—	1,086,729

13. DEFERRED CHARGES

	2004 $	2003 $
Deferred lease costs, net of accumulated amortization	429,943	—
Deferred financial instrument loss [note 23]	12,415	—
	442,358	—

14. INVESTMENT IN FINANCIAL SERVICES CONTRACTS

	2004 $	2003 $
Contracts with 19695 Yukon Inc. (i)	8,939,733	1,200,000
Debenture with RENTCASH (ii)	3,032,322	2,041,963
Debenture with hotelling business (iii)	500,000	—
	12,472,055	3,241,963

(i) During 2004 the Trust entered into additional financial services contracts totalling $7,700,000. The contracts have a term of ten years, pay the Trust a fixed fee of $0.07 per $100 loaned per day and are recallable at the Trust's option with thirty days notice. Costs associated with these contracts of $42,571 have been capitalized and are being amortized over the term of the contracts. $2,838 in amortization has been recorded for the year ended December 31, 2004. During 2003, the Trust had $1,200,000 in financial service contract outstanding under the same terms and conditions;

(ii) On July 15, 2004 the Trust entered into an agreement to provide a debenture in the amount of $1,000,000 to RENTCASH Inc. ("RENTCASH"). The non-revolving loan pays the Trust interest at a rate of 12% and a financing fee of 4% per annum. The loan matures July 15, 2007. Costs associated with this debenture of $949 have been capitalized and are being amortized over the term of the debentures. $10,590 in amortization has been recorded for the year ended December 31, 2004. During 2003, the Trust entered into an agreement to provide a debenture in the amount of $2,000,000 to RENTCASH Inc. ("RENTCASH") under the same terms and conditions and recorded costs associated with this debenture of $41,963;

(iii) On August 19, 2004 the Trust entered into an agreement to provide a debenture in the amount of $500,000 to an unrelated third party in the hotelling business. The non-revolving loan pays the Trust interest at a rate of 14% plus net profit and incentive fees of 20% of annual net profits from the hotel investments. The loan matures August 19, 2008.

The estimated fair value of the financial services contracts at December 31, 2004 was $15,000,000 based on a third party valuation (December 31, 2003 – $3,822,222).

Subsequent to December 31, 2004 the Trust has entered into an additional financial services contract under the same terms as note 14(i) above in the amount of $1,250,000.

15. BANK INDEBTEDNESS

At December 31, 2004 the Trust has a combined revolving demand facility with a major Canadian bank in the amount of $38,225,000 bearing interest at prime plus one-quarter of one percent. The revolving facility is collateralized by a floating charge debenture over all of the Trust's assets. In addition, the Trust has an acquisition and development line of $5,000,000, bearing interest at bank prime plus one and one-half percent, to fund additional oil and gas acquisitions. Commencing December 31, 2004 the revolving demand loan limit is reduced monthly by $1,100,000 increasing to $1,200,000 monthly commencing January 31, 2005. Subsequent to year end the Trust's loan agreement was amended to stop the reduction of the limit and maintain a limit of $35,925,000. The Trust also has an operating line facility with another major Canadian bank in the amount of $500,000 bearing interest at prime plus one percent. This operating line facility is available for the operations in the Trust's energy services division.

As at December 31, 2004, $31,400,000 was drawn on the revolving demand facility and $75,000 was drawn on the operating line facility. The effective interest rate on borrowings under these lines for the year ended December 31, 2004 including services fees was 4.66% (December 31, 2003 – 6.5%).

The Trust also had two letters of credit outstanding in the aggregate amount of $255,000.

16. MORTGAGES

The following mortgages were acquired as part of the Trust's acquisition of Western Spirit (see note 5):

	2004 $
Various mortgages with interest rates ranging from 5.75% to 8.15% (weighted average rate of 7.5%), maturities from March 2005 to September 2006, collateralized by first charge over the related properties, and restricted cash	12,133,681
Current portion of mortgages	(5,024,920)
	7,108,761

Approximate principal repayments required to maturity are as follows:

	$
2005	5,024,920
2006	7,108,761
	12,133,681

Upon maturity, the Trust intends to re-mortgage the properties.

Subsequent to the year end the Trust renewed a mortgage in the amount of $5,040,047 which matured in March 2005. It has been renewed for a three year term at an interest rate of 4.85%. Accordingly this mortgage has been classified as long-term at December 31, 2004.

The fair value of the mortgages payable has been determined by discounting the cash flows of these financial obligations using December 31, 2004 market rates for debt of similar terms. Based on these assumptions, the fair value as at December 31, 2004 of the mortgages has been estimated at $12,311,707 (December 31, 2003 – Nil).

17. CAPITAL LEASE OBLIGATIONS

The Trust has a capital lease for equipment which is repayable in monthly installments of $5,537 including interest at a fixed interest rate of 8% per annum. The lease matures on June 6, 2005 and is collateralized by specific equipment purchased.

Future minimum lease payments at December 31, 2004 are as follows:

	$
2005 Total minimum lease payments	33,221
Less amount representing interest	(762)
	32,459
Current portion of minimum lease payments	(32,459)
	—

18. LONG-TERM DEBT

The Trust has the following long-term loans outstanding which are collateralized by energy services equipment:

	2004 $
Various loans payable in monthly instalments ranging from $3,023 and $7,558, interest rates ranging from prime plus 2.61% to prime plus 2.65%, and maturities from December 10, 2005 to February 23, 2007	1,466,314
Various loans payable in monthly instalments ranging from $599 to $2,972, interest rates ranging from 0.00% to 4.30% , and maturities from September 23, 2007 to September 15, 2008	139,349
	1,605,663
Current portion	693,888
	911,775

There is no difference in the carrying value of these loans versus the fair value as a majority of the loans were entered into during the last quarter of 2004.

Approximate principal repayments required to maturity are as follows:

	$
2005	693,888
2006	596,649
2007	298,498
2008	16,628
	1,605,663

19. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligations to be $8,033,301 as at December 31, 2004 based on a total future liability of $19,164,503. These payments are expected to be made over the next 2 to 31 years. The Trust's credit adjusted risk free rate of 8.5% and an inflation rate of 2% were used to calculate the present value of the asset retirement obligation.

The following table reconciles the Trust's total asset retirement obligation:

	$
Carrying amount, as at January 1, 2003	—
Change in liability due to activities during the year	1,233,963
Asset retirement obligation accretion for the year	79,002
Carrying amount, as at December 31, 2003	1,312,965
Oil and gas property acquisitions during the year	6,065,739
Change in estimate	412,649
Asset retirement obligation accretion for the year	241,948
Carrying amount, as at December 31, 2004	8,033,301

20. UNITHOLDERS' CAPITAL

a) Unitholders' capital

Authorized

Authorized capital consists of an unlimited number of Trust Units, without par, and an unlimited number of Special Voting Units, without par. No Special Voting Units have been issued to date.

Issued

On June 10, 2004, as disclosed in the Trust's information circular with respect to the annual and special meeting of Unitholders, the Trust obtained unitholder approval to consolidate the number of outstanding units on a 1 for 15 basis. These audited consolidated financial statements have been updated to reflect the impact on the net income (loss) per unit as if the reverse stock split had occurred prior to the periods presented in these audited consolidated financial statements.

Trust Units	Number of Units	Amount $
Balance December 31, 2002	—	—
Units issued on 928719 corporate purchase (note 1)	509,991	1,325,182
Units issued on Onward Trust conversion (note 1)	146,289	877,749
Units from Special Warrants financing January 16, 2003 (note 1)	677,241	4,063,520
Units financing February 27, 2003 (note 1)	77,782	466,700
Units issued on Outback Acquisition (note 7)	155,554	1,050,011
Units issued on private placement	1,066,648	8,000,000
Units issued on 728409 Acquisition (note 6)	133,331	1,000,000
Trust unit issue costs	—	(931,220)
Balance December 31, 2003	2,766,836	15,851,942
Units issued on Western Spirit corporate purchase (i)	332,500	2,992,512
Units issued on financing June 28, 2004 (ii)	3,833,300	28,749,750
Units issued on Cascade Partnership purchase (iii)	266,667	2,000,000
Units issued on financing November 14, 2004 (iv)	4,472,221	40,250,000
Trust unit issue costs	—	(5,181,954)
Balance December 31, 2004	11,671,524	84,662,250

(i) On March 31, 2004 the Trust issued 332,500 trust units at a value of $2,992,512 in connection with its acquisition of Western Spirit (see note 5).

(ii) On June 28, 2004 the Trust completed a public offering by way of a prospectus for proceeds of $28,749,750. Costs associated with this transaction amounted to $2,376,548.

(iii) On June 30, 2004 the Trust issued 266,667 trust units at a value of $2,000,000 in connection with its acquisition of the Cascade Partnership (see note 4).

(iv) On November 15, 2004 the Trust completed a public offering by way of a prospectus for proceeds of $40,250,000. Costs associated with this transaction amounted to $2,805,406.

b) Net income per unit

For the year ended December 31, 2004, the Trust had a weighted average number of trust units outstanding of 5,685,210 (December 31, 2003 – 1,841,437). The diluted per unit amount was calculated assuming the exercise of outstanding in-the-money options resulting in a weighted average number of trust units outstanding for the year ended December 31, 2004, of 5,747,845 (December 31, 2003 – 1,878,821). At December 31, 2004 there were no anti-dilutive options.

c) Contributed surplus

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

	2004 $	2003 $
Contributed surplus, beginning of year	119,868	—
Compensation expense [note 21]	202,196	119,868
Contributed surplus, end of year	322,064	119,868

21. STOCK-BASED COMPENSATION

Under the Trust's unit option plan, options to acquire trust units are granted to employees and directors from time to time at exercise prices equal to the market value of the units at the date of the grant. Options granted under the plan vest over a three-year period and have a five-year life. The exercise price of the options is periodically adjusted to reflect the Trust's monthly distributions. Any consideration paid on exercise of stock options is credited to unitholders capital. A total of 309,933 units have been reserved under this plan.

At December 31, 2004 a total of 261,030 options vesting over three years had been granted under the Trust unit option plan and 41,109 of the outstanding options had vested. 106,666 of the options granted to date have an exercise price of $6.00, 16,665 options have an exercise price of $7.50, 6,666 options have an exercise price of $7.65 and the remaining 131,033 options have an exercise price of $9.00. The average remaining life of the options is 3.37 years (2003 – 4.18 years) and the weighted average remaining vesting period of the options is 1.15 years (2003 – 1.18 years). For the year ended December 31, 2004 no options were forfeited or expired.

Based on the year end unit price the Trust recorded compensation expense and contributed surplus of $202,196 in the year ended December 31, 2004 (December 31, 2003 - $119,868). The value of stock-based compensation was calculated using a Black-Scholes option-pricing model to estimate the fair value of stock options at the date of grant. The assumptions made for the options granted in 2004 include a volatility factor of expected market price of 21.3% (2003 – ranging from 40% to 44.1%), a weighted average risk-free interest rate of 4.25% (2003 – ranging from 4.5% to 5%), a dividend yield of 12% (2003 – nil%) and a weighted average expected life of options of 5 years (2003 – 5 years). No options were issued in years prior to January 1, 2003.

Subsequent to December 31, 2004 the Trust issued an additional 72,400 options.

22. REAL ESTATE CO-OWNERSHIP AGREEMENT

These consolidated financial statements include the Trust's 50% interest in the respective assets, liabilities, revenue and expenses of an co-ownership agreement. The following amounts represent the Trust's interest in the related assets, liabilities, revenue and expenses relating to the co-ownership agreement as at and for the year ended (as this real estate property was acquired in 2004 there are no balances relating to 2003):

	2004 $	2003 $
Assets	1,303,465	—
Liabilities	910,821	—
Revenue	120,932	—
Operating expenses	66,199	—
Net income	54,733	—
Cash flow from operating activities	67,352	—

23. FINANCIAL INSTRUMENTS

a) Fair values of financial assets and liabilities

The Trust's financial instruments consist of cash, restricted cash, accounts receivable, risk management asset, investment in financial services contracts, bank indebtedness, accounts payable, distributions payable, capital lease obligations, mortgages and long-term debt. Unless otherwise noted, as at December 31, 2004 and 2003, there were no significant differences between the carrying amounts of these financial instruments and their estimated fair values.

b) Credit risk

The Trust's financial instruments that are exposed to credit risk consist primarily of trade accounts receivable and financial services contracts. Although a substantial portion of trade receivables is dependant upon the strength of the Canadian oil and gas industry, management considers credit risk to be minimal. Management routinely assesses the financial strength of partners and customers, and monitors the exposure for credit losses.

Of the Trust's significant individual accounts receivable as at December 31, 2004, approximately 17% (December 31, 2003 – 23% due from one company) was due from 2 company relating to oil and gas sales in relation to trade accounts receivable.

With respect to financial instruments, the Trust could be exposed to losses if the counter party fails to perform in accordance with the terms of the contract. This risk is managed by diversifying the derivative portfolio among counter parties meeting certain financial criteria.

The Trust's financial services contracts are with affiliates of a financial services provider and with a chain of cash advance stores. The stated return on the financial services contracts and the principal are subject to significant credit risk. The Trust has attempted to mitigate this risk through the advancing of amounts through various counter parties, however, some credit risk remains. Under the Trust's revenue recognition policy, fees earned on these contracts are adjusted to reflect anticipated credit losses. Although no credit loss provision currently exists, a credit loss provision will be established when management deems the risk of credit loss to be significant.

c) Risk management asset (liability) and deferred financial instrument loss

As disclosed in note 3, as at January 1, 2004 the fair value of all outstanding instruments was recorded on the balance sheet with an offsetting deferred financial instrument loss. The deferred financial instrument loss is recognized in net income over the life of the associated contracts. Changes in fair value after January 1, 2004 are recorded on the balance sheet with the associated unrealized gain or loss recorded in net income. The estimated fair value of all financial instruments is based on quoted market prices or, in their absence, third party market indicators and forecasts.

The following table presents a reconciliation of the risk management liability and the deferred financial instrument loss:

	$
Risk management asset (liability), January 1, 2004	(125,676)
Change in mark-to-market unrealized gain (loss)	1,159,542
Change in recognized loss relating to expired contracts	113,261
Risk management asset (liability), December 31, 2004	1,147,127
Deferred financial instrument loss, January 1, 2004	125,676
Loss recognized relating to expired contracts	113,261
Deferred financial instrument loss, December 31, 2004	12,415

The Trust has the following fixed price forward contracts outstanding:

- A fixed price AECO natural gas swap for the period November 1, 2004 to October 31, 2006 on 700 gigajoules (“GJ”)/day of gas at a price of $7.17 Cdn/GJ
- A fixed price AECO natural gas swap for the period January 1, 2005 to March 31, 2005 on 500 GJ/day of gas at a price of $7.60 Cdn/GJ
- A fixed price AECO natural gas swap for the period November 1, 2006 to October 31, 2007 on 700 GJ/day of gas at a price of $6.64 Cdn/GJ
- A NYMEX natural gas floor for the period April 1, 2005 to October 31, 2005 on 40000 Mmbtu/Month of gas at a price of $4.50 US/Mmbtu
- A fixed price WTI swap for the period July 1, 2004 to June 30, 2005 on 100 barrels (“Bbl”)/day of crude oil at a price of $27.78 US/Bbl
- A fixed price WTI swap for the period January 1, 2005 to December 31, 2006 on 200 barrels/day of crude oil at a price of $40.50 US/Bbl
- A fixed price WTI collar for the period November 1, 2004 to October 31, 2007 on 70 barrels/day of crude oil with a floor price of $38.00 US/Bbl and a ceiling price of $44.65 US/Bbl
- A fixed price WTI floor for the period December 1, 2004 to November 30, 2007 on 170 barrels/day of crude oil with a floor price of $40.00 US/Bbl

d) Interest Rate Risk

Drawings under the Trust’s bank credit facilities are at floating interest rates and expose the Trust to interest rate risk. The Trust is also exposed to interest rate risk on maturity and refinancing of its fixed rate mortgages including the possibility that existing mortgages may not be refinanced or may not be refinanced on as favorable terms or with interest rates as favorable as those of the existing debt. The Trust mitigates these risks by its continued efforts to enhance the value of its real estate properties and maintain high occupancy levels.

24. RELATED PARTY TRANSACTIONS

In addition to the related party transactions described elsewhere in these consolidated financial statements, the Trust entered into the following transactions with related parties which are recorded at exchange amounts:

- During the year ended December 31, 2004, the Trust paid $106,414 (December 31, 2003 – $85,654) to Avenir Capital Corporation (“Avenir”), a significant unitholder of the Trust for rent, administration and advisory services.
- Included in accounts payable is $27,104 owing to Avenir relating to administration and advisory services and $202,592 owing to Avenir relating to the acquisition of certain oil and gas properties disclosed in note 11 with no fixed terms of repayment.
- As outlined in the original offering circular converting Onward Energy Inc. into a trust and the amalgamation with 928719 Alberta Ltd., a commitment was made to the chief executive and financial officers of the Trust that they would be entitled to a combined payment of $240,000 in cash or Trust Units if the business plan of the Trust was filled out through a real estate acquisition under specific conditions. Accordingly, with the closing of the Western Spirit acquisition (see note 5), the Trust has included $240,000 in accounts payable.

- During the year ended December 31, 2004, the Trust paid $150,000 to a director of the Trust for consulting fees relating to financial consulting services provided.
- During the year ended December 31, 2004, the Trust incurred marketing fees of $75,690 payable to a company with a shareholder who is also a unitholder of the Trust. Of this balance $12,000 is included in accounts payable and accrued liabilities as at December 31, 2004.

25. COMMITMENTS

At December 31, 2004, the following contracts were outstanding with respect to the physical deliveries of oil and gas product:

- A physical fixed price sale for the period November 1, 2004 to October 31, 2005 on 700 gigajoules/day of gas at a price of $5.94/ gigajoule.
- A physical fixed price sale for the period November 1, 2004 to March 31, 2005 on 500 gigajoules/day of gas at a price of $7.18/ gigajoule.
- A physical fixed price sale for the period November 1, 2004 to October 31, 2007 on 1,050 gigajoules/day of gas at a price of $6.55/ gigajoule.

Subsequent to December 31, 2004 the Trust entered into the following physical delivery contracts:

- A physical fixed price sale for the period April 1, 2005 to October 31, 2005 on 750 gigajoules/day of gas at a price of $6.70/ gigajoule.

The Trust has the following long-term lease commitments with respect to its premises:

- A five year lease effective May 1, 2004 with a monthly payment of $9,700;
- A five year lease effective December 15, 2004 with a monthly payment of $8,166;
- A five year lease effective February 1, 2005 with a monthly payment of $9,425 and
- A two year lease effective January 1, 2005 with a monthly payment of $4,825.

The payments over the remaining terms of these lease agreements are as follows:

	$
2005	375,967
2006	385,392
2007	327,492
2008	327,492
2009	241,726
2010	9,425
	1,667,494

The Trust indemnifies its directors and officers who are, serving at the Trust's request in such capacities. These costs have not been material to the Trust's financial position, operations, or cash flows. The Trust has acquired and maintains liability insurance for its directors and officers.

26. NON-CONTROLLING INTEREST

Non-controlling interest arose from the Trust's acquisition of 90% of Cascade Services Partnership and the acquisition of Indy Oilfield Ltd (see note 4).

	2004 **$**
Opening non-controlling interest, January 1, 2004	—
Acquisition of Cascade Partnership	253,916
Acquisition of Indy Oilfield Ltd.	4,524
Non-controlling interest in earnings for the year	67,982
Distributions payable to non-controlling interest holders	(66,667)
Closing non-controlling interest, December 31, 2004	259,755

27. FUTURE INCOME TAXES

The difference between the accounting value and the income tax value of assets and liabilities, which comprise the future tax liability, are as follows:

	2004 $	2003 $
Property and equipment	12,355,091	60,667
Asset retirement obligation	(2,728,109)	(454,548)
	9,626,982	(393,881)
Valuation allowance	—	393,881
	9,626,982	—

The future income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial income tax rate of 38.87 percent as follows:

	2004 $	2003 $
Earnings before income taxes	4,082,433	446,843
Statutory income tax rate	38.87%	40.75%
	1,586,842	182,089
Increase (decrease) resulting from:		
Non-deductible crown charges	580,590	18,242
Resource allowance	(228,016)	(42,765)
Trust distributions	(1,948,807)	(515,644)
Temporary differences not recognized at the subsidiary level	—	317,848
Non-taxable capital gain	—	(11,365)
Non-deductible stock based compensation expense	78,594	48,846
Other	(69,203)	2,749
	—	—

28. SEGMENTED INFORMATION

The Trust determines its reportable segments based on the structure of its operations, which are primarily focused on four principal business segments – oil and gas, financial services, real estate and energy services. The accounting policies followed by these business segments are the same as those described in the summary of significant accounting polices. During 2004 there were no inter-segment eliminations (2003 – nil).

The following is selected financial information for each business segment:

	For the year ended	
	December 31, 2004 $	December 31, 2003 $
Revenue, net		
Oil and Gas	14,652,028	4,039,437
Financial Services	1,358,908	411,596
Real Estate	2,018,475	—
Energy Services	3,877,905	—
	21,907,316	4,451,033

	For the year ended	
	December 31, 2004 $	December 31, 2003 $
Operating expenses		
Oil and Gas	3,089,847	1,021,601
Financial Services	12,000	—
Real Estate	753,942	—
Energy Services	1,915,684	—
	5,771,473	1,201,601

	For the year ended	
	December 31, 2004 $	December 31, 2003 $
Net Income		
Oil and Gas	2,574,346	146,986
Financial Services	1,293,593	299,857
Real Estate	(314,072)	—
Energy Services	460,584	—
	4,014,451	446,843

	2004				
	Oil and Gas $	Financial Services $	Real Estate $	Energy Services $	Total $
Selected balance sheet items					
Property and equipment	95,865,501	15,000	19,687,628	5,254,559	120,822,688
Investment in financial services contracts	—	12,472,055	—	—	12,472,055
Goodwill and other intangibles	5,025,155	—	1,914,064	3,155,990	10,095,209
Total assets	109,368,101	13,164,019	22,424,501	10,358,232	155,314,853
Bank indebtedness	31,400,000	—	—	75,000	31,475,000
Mortgages	—	—	12,133,681	—	12,133,681
Long-term debt	—	—	—	1,605,663	1,605,663

29. CASH DISTRIBUTIONS

Cash distributions declared per Trust unit issued and outstanding:

Period covered	Date of Distribution	Per Unit $
January 1, 2004 to January 31, 2004	02/13/2004	0.08745
February 1, 2004 to February 29, 2004	03/15/2004	0.08745
March 1, 2004 to March 31, 2004	04/15/2004	0.08745
April 1, 2004 to April 30, 2004	05/14/2004	0.08745
May 1, 2004 to May 31, 2004	06/15/2004	0.08745
June 1, 2004 to June 27, 2004	07/15/2004	0.07870
June 28, 2004 to June 30, 2004	07/15/2004	0.00880
July 1, 2004 to July 31, 2004	08/16/2004	0.08750
August 1, 2004 to August 31, 2004	09/15/2004	0.09625
September 1, 2004 to September 30, 2004	10/15/2004	0.09625
October 1, 2004 to October 31, 2004	11/15/2004	0.09625
November 1, 2004 to November 30, 2004	12/15/2004	0.09625
December 1, 2004 to December 31, 2004	01/17/2005	0.10600

As at December 31, 2004, the Trust had distributions owing of $1,237,182 (December 31, 2003 - $241,964). This was paid subsequent to year end on January 17, 2005.

30. SUBSEQUENT EVENTS

On March 28, 2005 the Trust announced that 91.38% of the issued and outstanding common shares of Val Vista Energy Ltd. ("Val Vista") have been tendered to the offer dated February 15, 2005 ("Offer") to purchase all of the issued and outstanding Val Vista shares. The Trust will proceed to take up and pay for all of the Val Vista shares deposited under the Offer. The Trust will also proceed to acquire all of the remaining outstanding Val Vista shares pursuant to the compulsory acquisition provisions of the Business Corporations Act. The consideration given to the Val Vista shareholders will be a combination of cash and Trust Units. The cash portion has a maximum of $12,666,600 and the maximum number of Trust Units to be issued is 1,183,795.

On February 6, 2005 the Trust entered into an agreement where by the Trust would acquire all of the assets of Elbow River Resources Ltd. for total cash consideration of $51.8 million and $6 million of Trust Units. The Trust Units will be held in Escrow until certain conditions of the agreement are met. This acquisition is scheduled to close on April 1, 2005.

On March 21, 2005 the Trust completed a public offering involving the issuance of 11,605,504 Trust Units, including the exercise of an over-allotment option for 1,513,761 Trust Units, at a price of $10.90 per Trust Unit for gross proceeds of $126,499,994. The net proceeds of the offering will be used for continued growth and development in its oil and gas, financial services, real estate and energy services operations.

CORPORATE INFORMATION

Directors

William M. Gallacher [2,3]
President & CEO
Calgary, Alberta

Gary Dundas
VP Finance & CFO
Calgary, Alberta

Alan Moon [1,2]
Calgary, Alberta

David Butler [1,3]
Calgary, Alberta

Stuart Chow [2,3]
Calgary, Alberta

Jeff Kohn (1,2)
Calgary, Alberta

1 Audit Committee
2 Governance and Compensation Committee
3 Reserves Committee

Officers & Key Personnel

William Gallacher, P.Eng
President & CEO

Gary Dundas, CMA, MBA
Vice President, Finance & CFO

Jill Koskimaki, BBA
Manager Bus. Development

Michelle O'Grady, CA
Controller

James Burns, P. Geol., MBA
COO, Energy

Grant Leslie, P. Eng.
VP Operations, Energy

Debbie Carter
Controller, Energy

Ken Wagner
Energy Services

Advisors

Tonko Realty Advisors
Calgary, Alberta

Corporate Secretary

J.G. (Jeff) Lawson
Burnet, Duckworth & Palmer, LLP
Calgary, Alberta

Investor Relations

300, 808 - First Street SW
Calgary, Alberta T2P 1M9
Phone: (403) 237-9949
Fax: (403) 237-0903
Email: info@avenirtrust.com
www.avenirtrust.com

Auditors

Ernst & Young, LLP
Calgary, Alberta

Tax Advisors

KPMG, LLP
Calgary, Alberta

Bankers

National Bank of Canada
Calgary, Alberta

Evaluation Engineers

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Legal Counsel

Burnet, Duckworth & Palmer, LLP
Calgary, Alberta

Transfer Agent

Olympia Trust Company
Calgary, Alberta

WWW.AVENIRTRUST.COM