ARC ENERGY TRUST AUDITORS' REPORT

TO THE UNITHOLDERS OF ARC ENERGY TRUST:

We have audited the consolidated balance sheets of ARC Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of income 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, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Trust's internal control over financial reporting. Accordingly, we express no such opinion.

Deloitte & Touche LLP

CHARTERED ACCOUNTANTS

CALGARY, ALBERTA
FEBRUARY 3, 2006

CONSOLIDATED BALANCE SHEETS

As at December 31 (Cdn$ thousands)	**2005**	2004
ASSETS		
Current assets		
Cash and cash equivalents	**$ -**	$ 4,413
Accounts receivable	**122,956**	72,881
Prepaid expenses	**14,020**	9,878
Commodity and foreign currency contracts (Note 9)	**3,125**	22,294
	140,101	109,466
Reclamation fund (Note 4)	**23,491**	21,294
Property, plant and equipment (Note 5)	**2,929,977**	2,016,646
Goodwill	**157,592**	157,592
Total assets	**$ 3,251,161**	$ 2,304,998
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 148,587**	$ 103,572
Cash distributions payable	**39,839**	27,893
Current portion of long term debt (Note 6)	**-**	8,715
Commodity and foreign currency contracts (Note 9)	**7,167**	26,336
	195,593	166,516
Long-term debt (Note 6)	**526,636**	211,834
Other long-term liabilities (Note 7)	**12,360**	3,893
Asset retirement obligations (Note 8)	**165,053**	73,001
Future income taxes (Note 10)	**515,877**	300,406
Total liabilities	**1,415,519**	755,650
COMMITMENTS AND CONTINGENCIES (Note 18)		
NON-CONTROLLING INTEREST		
Exchangeable shares (Note 12)	**37,494**	35,967
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 11)	**2,230,842**	1,926,351
Contributed surplus (Note 14)	**6,382**	6,475
Accumulated earnings	**1,235,742**	878,807
Accumulated cash distributions (Note 13)	**(1,674,818)**	(1,298,252)
Total unitholders' equity	**1,798,148**	1,513,381
Total liabilities and unitholders' equity	**$ 3,251,161**	$ 2,304,998

See accompanying notes to the consolidated financial statements.

MAC H. VAN WIELINGEN
DIRECTOR

FRED DYMENT
DIRECTOR

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS

For the years ended December 31 (Cdn$ thousands, except per unit amounts)	**2005**	2004
REVENUES		
Oil, natural gas, and natural gas liquids	**$ 1,165,197**	$ 901,782
Royalties	**(235,293)**	(177,032)
	929,904	724,750
Realized loss on commodity and foreign currency contracts (Note 9)	**(87,558)**	(86,909)
Unrealized gain (loss) on commodity and foreign currency contracts	**–**	841
	842,346	638,682
EXPENSES		
Transportation	**14,289**	14,798
Operating	**142,240**	139,716
General and administrative	**42,746**	29,512
Interest on long-term debt (Note 6)	**16,946**	13,320
Depletion, depreciation and accretion (Notes 5 and 8)	**264,515**	239,674
Gain on foreign exchange (Note 17)	**(6,412)**	(20,713)
	474,324	416,307
Income before taxes	**368,022**	222,375
Capital and other taxes	**(3,882)**	(2,834)
Future income tax (expense) recovery (Note 10)	**(1,660)**	26,100
Net income before non-controlling interest	**362,480**	245,641
Non-controlling interest (Note 12)	**(5,545)**	(3,951)
Net income	**356,935**	241,690
Accumulated earnings, beginning of year	**878,807**	637,117
Accumulated earnings, end of year	**$ 1,235,742**	$ 878,807
Net income per unit (Note 16)		
Basic	**$ 1.90**	$ 1.32
Diluted	**$ 1.88**	$ 1.31

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31 (Cdn$ thousands)	2005	2004
CASH FLOW FROM OPERATING ACTIVITIES		
Net income after non-controlling interest	**$ 356,935**	$ 241,690
Add items not involving cash:		
Non-controlling interest	**5,545**	3,951
Future income tax expense (recovery)	**1,660**	(26,100)
Depletion, depreciation and accretion (Notes 5 and 8)	**264,515**	239,674
Non-cash gain on commodity and foreign currency contracts	**–**	(841)
Non-cash gain on foreign exchange (Note 17)	**(6,359)**	(18,427)
Non-cash trust unit incentive compensation (Notes 14 and 15)	**17,215**	8,086
Expenditures on site reclamation and restoration	**(4,881)**	(3,232)
Change in non-cash working capital	**(17,919)**	1,617
	616,711	446,418
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		
Borrowings (repayments) under revolving credit facilities	**258,190**	(162,555)
Issuance of senior secured notes	**62,478**	177,322
Repayment of senior secured notes	**(8,214)**	(8,347)
Issue of trust units	**259,691**	19,301
Trust unit issue costs	**(12,218)**	(152)
Cash distributions paid, net of distribution reinvestment (Note 13)	**(318,238)**	(301,936)
Payment of retention bonus	**(1,000)**	(1,000)
Change in non-cash working capital	**(179)**	(397)
	240,510	(277,764)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		
Corporate acquisitions, net of cash received (Note 3)	**(504,996)**	(39,385)
Acquisition of petroleum and natural gas properties	**(93,824)**	529
Proceeds on disposition of petroleum and natural gas properties	**2,538**	57,691
Capital expenditures	**(257,895)**	(192,591)
Net reclamation fund contributions (Note 4)	**(2,197)**	(4,113)
Change in non-cash working capital	**(5,260)**	1,333
	(861,634)	(176,536)
DECREASE IN CASH AND CASH EQUIVALENTS	**(4,413)**	(7,882)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**4,413**	12,295
CASH AND CASH EQUIVALENTS, END OF YEAR	**$ –**	$ 4,413

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004 (all tabular amounts in thousands Cdn$ except per unit and volume amounts)

1. STRUCTURE OF THE TRUST

ARC Energy Trust ("ARC" or the "Trust") was formed on May 7, 1996 pursuant to a Trust indenture (the "Trust Indenture") that has been amended from time to time, most recently on May 12, 2005. Computershare Trust Company of Canada was appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the trust units.

The Trust was created for the purposes of issuing trust units to the public and investing the funds so raised to purchase a royalty in the properties of ARC Resources Ltd. ("ARC Resources") and ARC Sask Energy Trust ("ARC Sask"). The Trust Indenture was amended on June 7, 1999 to convert the Trust from a closed-end to an open-ended investment Trust. The current business of the Trust includes the investment in all types of energy business-related assets including, but not limited to, petroleum and natural gas-related assets, gathering, processing and transportation assets. The operations of the Trust consist of the acquisition, development, exploitation and disposition of these assets and the distribution of the net cash proceeds from these activities to the unitholders.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management following Canadian generally accepted accounting principles ("GAAP"). These principles differ in certain respects from accounting principles generally accepted in the United States of America ("US GAAP") and to the extent that they affect the Trust, these differences are described in Note 20. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion, depreciation and accretion of the petroleum and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Trust and its subsidiaries. Any reference to "the Trust" throughout these consolidated financial statements refers to the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

REVENUE RECOGNITION

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

TRANSPORTATION

Costs paid by the Trust for the transportation of natural gas, crude oil and NGLs from the wellhead to the point of title transfer are recognized when the transportation is provided.

JOINT VENTURE

The Trust conducts many of its oil and gas production activities through joint ventures and the financial statements reflect only the Trust's proportionate interest in such activities.

DEPLETION AND DEPRECIATION

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit-of-production basis based on:

(a) total estimated proved reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;

(b) total capitalized costs, excluding undeveloped lands, plus estimated future development costs of proved undeveloped reserves, including future estimated asset retirement costs; and

(c) relative volumes of petroleum and natural gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

UNIT BASED COMPENSATION

The Trust has established a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust accounts for the rights using the fair value method, whereby the fair value of rights is determined on the date on which fair value can initially be determined. The fair value is then recorded as compensation expense over the period that the rights vest, with a corresponding increase to contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

WHOLE TRUST UNIT INCENTIVE PLAN COMPENSATION

The Trust has established a Whole Trust Unit Incentive Plan (the "Whole Unit Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. Compensation expense associated with the Whole Unit Plan is granted in the form of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs") and is determined based on the intrinsic value of the Whole Trust Units at each period end. The intrinsic valuation method is used as participants of the Whole Unit Plan receive a cash payment on a fixed vesting date. This valuation incorporates the period end trust unit price, the number of RTUs and PTUs outstanding at each period end, and certain management estimates. As a result, large fluctuations, even recoveries, in compensation expense may occur due to changes in the underlying trust unit price. In addition, compensation expense is deferred and recognized in earnings over the vesting period of the Whole Unit Plan with a corresponding increase or decrease in liabilities. Classification between accrued liabilities and other long-term liabilities is dependent on the expected payout date.

The Trust charges amounts relating to head office employees to general and administrative expense, amounts relating to field employees to operating expense and amounts relating to geologists and geophysicists to property, plant and equipment.

The Trust has not incorporated an estimated forfeiture rate for RTUs and PTUs that will not vest. Rather, the Trust accounts for actual forfeitures as they occur.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less when purchased.

PROPERTY, PLANT AND EQUIPMENT ("PP&E")

The Trust follows the full cost method of accounting. All costs of exploring, developing and acquiring petroleum and natural gas properties, including asset retirement costs, are capitalized and accumulated in one cost centre as all operations are in Canada. Maintenance and repairs are charged against income, and renewals and enhancements that extend the economic life of the PP&E are capitalized. Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 per cent or more.

IMPAIRMENT

The Trust places a limit on the aggregate carrying value of PP&E, which may be amortized against revenues of future periods.

Impairment is recognized if the carrying amount of the PP&E exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the PP&E to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Trust's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the Trust's future cash flows would be recorded as a permanent impairment.

The cost of unproved properties is excluded from the impairment test described above and subject to a separate impairment test.

GOODWILL

The Trust must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company. The goodwill balance is assessed for impairment annually at year end or as events occur that could result in an impairment. Impairment is recognized based on the fair value of the reporting entity (consolidated Trust) compared to the book value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

ASSET RETIREMENT OBLIGATIONS ("ARO")

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

INCOME TAXES

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Trust's corporate subsidiaries and their respective tax base, using substantively enacted future income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is 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 and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

Basic net income per unit is computed by dividing the net income by the weighted average number of units outstanding during the period. Diluted net income per unit amounts are calculated giving effect to the potential dilution that would occur if rights were exercised at the beginning of the period. The treasury stock method assumes that proceeds received from the exercise of in-the-money rights and any unrecognized trust unit incentive compensation are used to repurchase units at the average market price.

DERIVATIVE FINANCIAL INSTRUMENTS

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by the Trust to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. The Trust considers all of these transactions to be effective economic hedges, however, the majority of the Trust's contracts do not qualify or have not been designated as effective hedges for accounting purposes.

For derivative instruments that do qualify as effective accounting hedges, policies and procedures are in place to ensure that the required documentation and approvals are in place. This documentation specifically ties the derivative financial instrument to its use, and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust also identifies all relationships between hedging instruments and hedged items, as well as its risk management objective and the strategy for undertaking hedge transactions. This would include linking the particular derivative to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. Where specific hedges are executed, the Trust assesses, both at the inception of the hedge and on an ongoing basis, whether the derivative used in the particular hedging transaction is effective in offsetting changes in fair value or cash flows of the hedged item.

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

For transactions that do not qualify for hedge accounting, the 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 statement of income for the current period.

FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the consolidated balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

NON-CONTROLLING INTEREST

The Trust must record non-controlling interest when exchangeable shares issued by a subsidiary of the Trust are transferable to third parties. Non-controlling interest on the consolidated balance sheet is recognized based on the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. Net income is reduced for the portion of earnings attributable to the non-controlling interest. As the exchangeable shares are converted to trust units, the non-controlling interest on the consolidated balance sheet is reduced by the cumulative book value of the exchangeable shares and unitholders' capital is increased by the corresponding amount.

RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2005.

3. CORPORATE ACQUISITIONS

REDWATER AND NORTH PEMBINA CARDIUM UNIT

On December 16, 2005 the Trust acquired all of the issued and outstanding shares of three legal entities, 3115151 Nova Scotia Company, 3115152 Nova Scotia Company and 3115153 Nova Scotia Company which together hold the Redwater and North Pembina Cardium Unit assets (collectively "Redwater and NPCU") for total consideration of $462.8 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired	
Working capital deficit	$ (629)
Property, plant and equipment	729,482
Asset retirement obligations	(70,700)
Future income taxes	(195,339)
Total net assets acquired	**$ 462,814**

Consideration Paid	
Cash consideration and fees paid	$ 462,814
Total consideration paid	**$ 462,814**

The acquisition of Redwater and NPCU has been accounted for as an asset acquisition pursuant to EIC-124.

In addition to consideration paid, the Trust committed to making contributions to a restricted reclamation fund as detailed in Note 18.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $463.4 million and the associated tax basis of $93.3 million.

These consolidated financial statements incorporate the operations of Redwater and NPCU from December 16, 2005.

ROMULUS EXPLORATION INC.

On June 30, 2005, the Trust acquired all of the issued and outstanding shares of Romulus Exploration Inc. ("Romulus") for total consideration of $42.2 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired	
Working capital deficit	$ (1,359)
Property, plant and equipment	62,456
Asset retirement obligations	(443)
Future income taxes	(18,472)
Total net assets acquired	**$ 42,182**

Consideration Paid	
Cash and fees paid	$ 42,182
Total consideration paid	**$ 42,182**

The acquisition of Romulus has been accounted for as an asset acquisition pursuant to EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $44 million and the associated tax basis of $9 million.

These consolidated financial statements incorporate the operations of Romulus from June 30, 2005.

HARRINGTON & BIBLER

On December 31, 2004, the Trust acquired all of the issued and outstanding shares of four legal entities – Harrington Oil & Gas Ltd., Bibler Oil & Gas Ltd., Lesco Oil & Gas Ltd., and Bibco Oil & Gas Ltd. ("Harrington & Bibler") – for total consideration of $41.4 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired	
Working capital surplus (including cash of $2,124)	$ 3,479
Property, plant and equipment	55,229
Future income taxes	(17,259)
Total net assets acquired	**$ 41,449**

Consideration Paid	
Cash and fees paid	$ 41,449
Total consideration paid	**$ 41,449**

The acquisition of Harrington & Bibler has been accounted for as an asset acquisition pursuant to EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $38 million and the associated tax basis of $5.3 million.

These consolidated financial statements incorporate the results of operations of the acquired Harrington & Bibler properties from December 31, 2004.

UNITED PRESTVILLE LTD.

On June 8, 2004, the Trust acquired all of the issued and outstanding shares of United Prestville Ltd. ("United Prestville") for total consideration of $30.6 million. The allocation of the purchase price and consideration paid were as follows:

Net Assets Acquired		
Working capital deficit	$	(2,569)
Property, plant and equipment		40,412
Future income taxes		(7,283)
Total net assets acquired	**$**	**30,560**

Consideration Paid		
Cash fees paid	$	60
Trust units issued		30,500
Total consideration paid	**$**	**30,560**

The acquisition of United Prestville has been accounted for as an asset acquisition pursuant to EIC-124.

The future income tax liability on acquisition was based on the difference between the fair value of the acquired net assets of $33.1 million and the associated tax basis of $19.3 million.

These consolidated financial statements incorporate the operations of United Prestville from June 8, 2004.

4. RECLAMATION FUND

	2005	2004
Balance, beginning of year	**$ 21,294**	$ 17,181
Contributions	**6,000**	6,000
Reimbursed expenditures (1)	**(4,644)**	(3,097)
Interest earned on fund	**841**	1,210
Balance, end of year	**$ 23,491**	$ 21,294

(1) Amount differs from actual expenditures incurred by the Trust due to timing differences.

A reclamation fund was established to fund future asset retirement obligation costs. The Board of Directors of ARC Resources has approved voluntary contributions over a 20 year period that result in minimum annual contributions of $6 million ($6 million in 2004) based upon properties owned as at December 31, 2005. In addition, the Trust has committed to a restricted reclamation fund associated with the Redwater property acquired in the Redwater and NPCU acquisition, detailed in Note 18. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distributions to the unitholders.

5. PROPERTY, PLANT AND EQUIPMENT

	2005	2004
Property, plant and equipment, at cost	**$ 4,141,958**	$ 2,969,319
Accumulated depletion and depreciation	**(1,211,981)**	(952,673)
Property, plant and equipment, net	**$ 2,929,977**	$ 2,016,646

The calculation of 2005 depletion and depreciation included an estimated $488 million ($374.2 million in 2004) for future development costs associated with proved undeveloped reserves and excluded $58.9 million ($52.5 million in 2004) for the cost value of unproved properties.

The Trust performed a ceiling test calculation at December 31, 2005 to assess the recoverable value of PP&E. Based on the calculation, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's PP&E at December 31, 2005. The benchmark prices used in the calculation are as follows:

Year	WTI Oil ($US/bbl)	AECO Gas (Cdn$/mmbtu)	USD/CAD Exchange Rates
2006	57.00	10.60	0.85
2007	55.00	9.25	0.85
2008	51.00	8.00	0.85
2009	48.00	7.50	0.85
2010	46.50	7.20	0.85
2011 - 2016	46.50	7.15	0.85
Remainder (1)	2.0%	2.0%	0.85

(1) Percentage change represents the change in each year after 2016 to the end of the reserve life.

6. LONG-TERM DEBT

	2005	2004
Revolving credit facilities		
Syndicated credit facility (1)	**$ 254,680**	$ –
Working capital facility	**3,800**	290
Senior secured notes		
8.05% USD Note	**–**	33,701
5.42% USD Note	**87,443**	–
4.94% USD Note	**34,977**	36,108
4.62% USD Note	**72,868**	75,225
5.10% USD Note	**72,868**	75,225
Total debt outstanding	**$ 526,636**	$ 220,549
Current portion of debt	**–**	8,715
Long-term debt	**$ 526,636**	$ 211,834

(1) Amount borrowed under the syndicated credit facility includes $2.9 million of outstanding cheques in excess of bank balance.

In April 2004, the Trust consolidated its credit facilities into one syndicated facility. The syndication did not impact security or covenants under the credit facility. As at December 31, 2005, the Trust has one syndicated credit facility and one working capital facility to a combined maximum of $950 million, less the amount of the outstanding senior secured notes.

Amounts due under the working capital facility and the senior secured notes in the next 12 months have not been included in current liabilities as management has the ability and intent to refinance this amount through the syndicated credit facility.

Security for the senior secured notes is in the form of floating charges on all lands and assignments. The senior secured notes rank pari passu to the revolving credit facilities.

The payment of principal and interest are allowable deductions in the calculation of cash available for distribution to unitholders and rank in priority to cash distributions payable to unitholders. Should the properties securing this debt generate insufficient revenue to repay the outstanding balances, the unitholders have no direct liability.

Interest paid during the year did not differ significantly from interest expense.

REVOLVING CREDIT FACILITIES

The syndicated revolving credit facility has a 364 day extendable revolving period and a two year term. Borrowings under the facility bear interest at bank prime (five per cent and 4.25 per cent at December 31, 2005 and December 31, 2004, respectively) or, at the Trust's option, Canadian dollar or US dollar bankers' acceptances plus a stamping fee. The lenders review the credit facility each year and determine whether they will extend the revolving periods for another year. The term date of the current credit facility is March 28, 2006.

In the event that the revolving periods are not extended, the loan balance will become repayable over a two year term period with 20 per cent of the loan balance outstanding on the term date payable on March 28, 2007 followed by three quarterly payments of five per cent of the loan balance. The remaining 65 per cent of the loan balance is payable in one lump sum at the end of the term period. Collateral for the loan is in the form of floating charges on all lands and assignments and negative pledges on specific petroleum and natural gas properties.

The working capital facility allows for maximum borrowings of $25 million and is due and payable immediately upon demand by the bank. The facility is secured and is subject to the same covenants as the credit facility.

8.05 PER CENT, 5.42 PER CENT AND 4.94 PER CENT SENIOR SECURED USD NOTES

These senior secured notes were issued in three separate issues pursuant to an Uncommitted Master Shelf Agreement. The US$35 million senior secured notes were issued in 2000, bore interest at 8.05 per cent, and had a remaining weighted average term of 2.3 years at January 1, 2005. During the year, the Trust repaid the total principal outstanding, incurring a make whole-premium in the amount of US$1.1 million, which was paid in order to early settle the debt. This make-whole premium was charged to interest expense in the year.

In conjunction with the early retirement of the above notes, additional US$75 million notes were issued on December 15, 2005. These notes bear interest at 5.42 per cent, have a remaining final term of 12 years (remaining weighted average term of 8.6 years) and require equal principal repayments over an eight year period commencing in 2010.

The US$30 million senior secured notes were issued in 2002, bear interest at 4.94 per cent, have a remaining final life of 4.8 years (remaining average life of 2.8 years) and require equal principal payments of US$6 million over a five year period commencing in 2006.

4.62 PER CENT AND 5.10 PER CENT SENIOR SECURED USD NOTES

These notes were issued on April 27, 2004 via a private placement in two tranches of US$62.5 million each. The first tranche of US$62.5 million bears interest at 4.62 per cent and has a remaining final term of 8.3 years (remaining weighted average term of 5.9 years) and require equal principal repayments over a six year period commencing 2009. Immediately following the issuance, the Trust entered into interest rate swap contracts that effectively changed the interest rate from fixed to floating (see Note 9). The second tranche of US$62.5 million bears interest at 5.10 per cent and has a remaining final term of 10.3 years (remaining weighted average term of 8.4 years). Repayments of the notes will occur in years 2012 through 2016.

7. OTHER LONG-TERM LIABILITIES

	2005	2004
Accrued long-term incentive compensation	**$ 11,360**	$ 1,893
Retention bonuses	**1,000**	2,000
Total other long-term liabilities	**$ 12,360**	$ 3,893

The accrued long-term incentive compensation represents the long-term portion of the Trust's estimated liability for the Whole Unit Plan as at December 31, 2005 (see Note 15). This amount is payable in 2007 through 2008.

The retention bonuses arose upon internalization of the management contract in 2002. The long-term portion of retention bonuses will be paid in August 2007.

8. ASSET RETIREMENT OBLIGATIONS ("ARO")

The total future ARO 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 ARO to be $165.1 million as at December 31, 2005 (2004 - $73 million) based on a total future undiscounted liability of $603.4 million ($247 million in 2004). These payments are expected to be made over the next 61 years with the bulk of payments being made in years 2016 to 2025 and 2046 to 2055. The Trust's weighted average credit adjusted risk free rate of 5.6 per cent (6.9 per cent in 2004) and an inflation rate of two per cent (1.5 per cent in 2004) were used to calculate the present value of the ARO. During the year, no gains or losses were recognized on settlements of ARO.

The following table reconciles the Trust's ARO:

	2005	2004
Carrying amount, beginning of year	**$ 73,001**	$ 66,657
Increase in liabilities relating to corporate acquisitions	**71,143**	–
Increase in liabilities relating to development activities	**5,096**	7,524
Increase (decrease) in liabilities relating to change in estimate	**15,487**	(2,528)
Settlement of liabilities during the year	**(4,881)**	(3,232)
Accretion expense	**5,207**	4,580
Carrying amount, end of year	**$ 165,053**	$ 73,001

9. FINANCIAL INSTRUMENTS

The Trust is exposed to a number of financial risks including the following items as part of its normal course of business:

RISK FACTORS

A) CREDIT RISK

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only highly rated entities and reviewing its exposure to individual entities on a regular basis. With respect to counterparties to financial instruments the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

B) VOLATILITY OF OIL AND NATURAL GAS PRICES

The Trust's operational results and financial condition, and therefore the amount of distributions paid to the unitholders are dependent on the prices received for oil and natural gas production. Oil and gas prices have fluctuated widely during recent years and are determined by economic, and in the case of oil prices, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions impact prices. Any movement in oil and natural gas prices could have an effect on the Trust's financial condition and therefore on the distributions to the unitholders. ARC may manage the risk associated with changes in commodity prices by entering into oil or natural gas price derivatives. To the extent that ARC engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

C) VARIATIONS IN INTEREST RATES AND FOREIGN EXCHANGE RATES

Increases in interest rates could result in a significant increase in the amount the Trust pays to service variable interest debt, resulting in a decrease in distributions to unitholders. World oil prices are quoted in US dollars and the price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate that may fluctuate over time. Variations in the exchange rate of the Canadian dollar could have significant positive or negative impact on future distributions. ARC has initiated certain derivative contracts to attempt to mitigate these risks. To the extent that ARC engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. The increase in the exchange rate for the Canadian dollar and future Canadian/US exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

FINANCIAL INSTRUMENTS

Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, reclamation fund, current liabilities, other long-term liabilities, commodity and foreign currency contracts and long-term debt. Except as noted below, as at December 31, 2005 and 2004, there were no significant differences between the carrying value of these financial instruments and their estimated fair value due to their short term nature.

The fair value of the US$230 million fixed rate senior secured approximated Cdn$269 million as at December 31, 2005 and will vary with changes in interest rates (2004 – US$183 million outstanding approximated Cdn$219 million).

DERIVATIVE CONTRACTS

During 2005, the Trust terminated certain 2006 crude oil and foreign currency contracts resulting in a payment of $6.1 million dollars (2004 – $4.9 million). This amount reduced net income in the year.

Following is a summary of all derivative contracts in place as at December 31, 2005 in order to mitigate the risks discussed above:

Financial WTI Crude Oil Contracts

Term	Contract	Volume (bbl/d)	Bought Put (US$/bbl)	Sold Put (US$/bbl)
2006				
Jan 06 – Mar 06	Bought Put	3,000	50.00	–
Jan 06 – Mar 06	Put Spread	1,000	55.00	45.00
Jan 06 – Jun 06	Put Spread	2,000	50.00	40.00
Jan 06 – Dec 06	Bought Put	1,000	55.00	–
Jan 06 – Dec 06	Put Spread	1,000	55.00	45.00
Apr 06 – Dec 06	Bought Put	2,000	50.00	–
Apr 06 – Dec 06	Put Spread	2,000	55.00	45.00
Annual Weighted Average		**6,992**	**52.68**	**43.68**

Financial AECO Natural Gas Contracts

Term	Contract	Volume (GJ/d)	Bought Put (Cdn$/GJ)	Sold Put (Cdn$/GJ)
2006				
Jan 06 – Mar 06	Bought Put	10,000	8.00	–
Jan 06 – Mar 06	Put Spread	20,000	8.50	6.50
Mar 06 – Mar 06	Put Spread	10,000	10.00	8.00
Apr 06 – Oct 06	Put Spread	30,000	8.00	6.00
Annual Weighted Average		**25,836**	**8.16**	**6.18**

Financial AECO/NYMEX Natural Gas Basis Contracts

Term	Contract	Volume (mmbtu/d)	Bought Put (US$/mmbtu)
2006			
Jan 06 – Mar 06	Bought Put	10,000	8.00
Annual Weighted Average		**2,466**	**8.00**

Financial Foreign Exchange Contracts

Term	Contract	Volume (millions US$)	Swap (Cdn$/US$)	Swap (US$/Cdn$)
USD Sales Contracts				
2006				
Jan 06 – Jun 06	Swap	37.1	1.2239	0.8172
Jan 06 – Dec 06	Swap	60.0	1.1659	0.8577
Annual Weighted Average		**78.6**	**1.1880**	**0.8417**

Term	Contract	Volume (millions US$)	Swap (Cdn$/US$)	Swap (US$/Cdn$)
USD Purchase Contracts				
2006				
Oct 06 – Dec 06	Swap	15.0	1.1685	0.8558
Annual Weighted Average		**3.8**	**1.1685**	**0.8558**

Financial Electricity Contracts (1)

Term	Contract	Volume (MWh)	Swap (Cdn$/MWh)
Jan 06 – Dec 10	Swap	5.0	63.00

(1) Contracted volume is based on a 24/7 term.

Financial Interest Rate Contracts (1)

Term	Contract	Principal (millions US$)	Fixed Annual Rate (%)	Spread on 3 Mo. LIBOR
Jan 06 – Apr 14	Swap	30.5	4.62	38.5 bps
Jan 06 – Apr 14	Swap	32.0	4.62	(25.5 bps)
Total and Annual Weighted Average		**62.5**	**4.62**	**5.5 bps**

(1) Interest rate swap contracts have an optional termination date of April 27, 2009. The Trust has the option to extend the optional termination date by one year on the anniversary of the trade date each year until April 2009. Starting in 2009, the contract amount decreases annually until 2014. The Trust pays the floating interest rate based on the three month LIBOR plus a spread and receives the fixed interest rate.

The Trust has designated its fixed price electricity contract as an effective accounting hedge as at January 1, 2004. A realized gain of $0.3 million ($0.4 million loss in 2004) on the electricity contract has been included in operating costs. The fair value unrealized loss on the electricity contract of $0.2 million has not been recorded on the consolidated balance sheet at December 31, 2005.

Previously the Trust had entered into two interest rate swap contracts to manage the Trust's interest rate exposure on debt instruments. These contracts were designated as effective accounting hedges on the contract date. During the year one of these contracts was unwound at a nominal cost. In November 2005 the Trust entered into a new interest rate swap contract which it also designated as an effective accounting hedge. A realized gain of $0.5 million for the year on the interest rate swap contracts has been included in interest expense ($1.4 million gain in 2004). The fair value unrealized loss on the remaining two interest rate swap contracts of $1 million has not been recorded on the consolidated balance sheet at December 31, 2005.

None of the Trust's commodity and foreign currency contracts have been designated as effective accounting hedges. Accordingly, all commodity and foreign currency contracts have been accounted as assets and liabilities in the consolidated balance sheet based on their fair values.

The following table reconciles the movement in the fair value of the Trust's financial commodity and foreign currency contracts that have not been designated as effective accounting hedges:

	2005	2004
Fair value, beginning of year (1)	**$ (4,042)**	$ (14,575)
Fair value, end of year	**(4,042)**	(4,042)
Change in fair value of contracts in the year (1)	**–**	10,533
Realized losses in the year	**(87,558)**	(86,909)
Non-cash amortization of crystallized hedging gains	**–**	4,883
Amortization of opening mark to market loss	**–**	(14,575)
Loss on commodity and foreign currency contracts (1)	**$ (87,558)**	$ (86,068)
Commodity and foreign currency contracts liability	**$ (7,167)**	$ (26,336)
Commodity and foreign currency contract asset	**$ 3,125**	$ 22,294

(1) Excludes the fixed price electricity contract and interest rate swap contracts that were accounted for as effective accounting hedges.

Upon implementation of the new hedge accounting guideline on January 1, 2004, the Trust recorded a liability and corresponding deferred hedge loss of $14.6 million for the fair value of the contracts at that time. The opening deferred hedge loss was amortized to income over the terms of the contracts in place at January 1, 2004. As at December 31, 2004, the deferred hedge loss had been fully amortized. At December 31, 2005, the fair value of the contracts that were not designated as accounting hedges was a loss of $4 million ($4 million in 2004).

The Trust recorded a loss on commodity and foreign currency contracts of $87.6 million in the statement of income for 2005 ($86.1 million in 2004). This amount includes the realized and unrealized gains and losses on derivative contracts that do not qualify as effective accounting hedges. During the year, no unrealized gain/loss was recognized as there was no over-all change in fair value of the contracts ($10.5 million unrealized gain in 2004). Realized cash losses on contracts during the year of $87.6 million ($86.9 million in 2004) and amortization expense of $nil of the opening deferred hedge loss ($14.6 million in 2004) have been included in this amount. In addition, this amount includes a non-cash amortization gain of $nil ($4.9 million in 2004) relating to contracts that were previously recorded on the consolidated balance sheet.

10. FUTURE INCOME TAXES

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to income before future income tax recovery as follows:

	2005	2004
Income before future income tax expense and recovery	**$ 364,140**	$ 219,541
Expected income tax expense at statutory rates	**136,990**	85,410
Effect on income tax of:		
Net income of the Trust	**(111,687)**	(86,547)
Effect of change in corporate tax rate	**(4,885)**	(5,861)
Resource allowance	**(20,036)**	(13,341)
Unrealized (gain) on foreign exchange	**(1,588)**	(8,412)
Non-deductible crown charges	**1,265**	1,304
Alberta Royalty Tax Credit	**141**	244
Capital tax	**1,460**	1,103
Future income tax expense (recovery)	**$ 1,660**	$ (26,100)

The net future income tax liability is comprised of the following:

	2005	2004
Future tax liabilities:		
Capital assets in excess of tax value	**$ 569,812**	$ 345,987
Future tax assets:		
Non-capital losses	**(1,509)**	(19,429)
Asset retirement obligations	**(45,755)**	(19,434)
Commodity and foreign currency contracts	**(1,364)**	(1,384)
Attributed Canadian royalty income	**(5,289)**	(5,289)
Deductible share issue costs	**(18)**	(45)
Net future income tax liability	**$ 515,877**	$ 300,406

The petroleum and natural gas properties and facilities owned by the Trust's corporate subsidiaries have an approximate tax basis of $567.2 million ($364.6 million in 2004) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry forwards of $4.5 million ($56.7 million in 2004) that expire in the years through 2010.

$0.9 million of current income tax was accrued for in 2005 relating to a predecessor company. No current income taxes were paid or payable in 2004.

11. UNITHOLDERS' CAPITAL

The Trust is authorized to issue 650 million units of which 199.1 million units were issued and outstanding as at December 31, 2005 (185.8 million as at December 31, 2004).

On December 23, 2005, the Trust issued nine million units at $26.65 per unit for proceeds of $239.9 ($227.6 million net of trust unit issue costs) pursuant to a public offering prospectus dated December 16, 2005.

The Trust has in place a Distribution Reinvestment and Optional Cash Payment Program Plan ("DRIP") in conjunction with the Trust's transfer agent to provide the option for unitholders to reinvest cash distributions into additional units issued from treasury at a five per cent discount to the prevailing market price with no additional fees or commissions.

The Trust is an open ended mutual fund under which unitholders have the right to request redemption directly from the Trust. Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the date units are tendered or 90 per cent of the weighted average trading price for the 10 day trading period commencing on the tender date. Cash payments for units tendered for redemption are limited to $100,000 per month with redemption requests in excess of this amount eligible to receive a note from ARC Resources for a maximum of $500 million accruing interest at six per cent and repayable within 15 years.

	2005		2004	
	Number of Trust Units	**$**	Number of Trust Units	$
Balance, beginning of year	**185,822**	**1,926,351**	179,780	1,843,112
Issued for cash	**9,000**	**239,850**	–	–
Issued for properties (Note 3)	**–**	**–**	2,032	30,500
Issued on conversion of ARL exchangeable shares (Note 12)	**333**	**4,018**	363	4,295
Issued on exercise of employee rights (Note 14)	**1,500**	**24,052**	1,751	20,672
Distribution reinvestment program	**2,449**	**48,789**	1,896	27,924
Trust unit issue costs	**–**	**(12,218)**	–	(152)
Balance, end of year	**199,104**	**2,230,842**	185,822	1,926,351

12. EXCHANGEABLE SHARES

The ARC Resources exchangeable shares ("ARL Exchangeable Shares") were issued on January 31, 2001 at $11.36 per exchangeable share as partial consideration for the Startech Energy Inc. acquisition. The issue price of the exchangeable shares was determined based on the weighted average trading price of units preceding the date of announcement of the acquisition. The ARL Exchangeable Shares had an exchange ratio of 1:1 at the time of issuance.

ARL Exchangeable Shares can be converted (at the option of the holder) into units at any time. The number of units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the ten day weighted average unit price preceding the record date. The exchangeable shares are not eligible for distributions and, in the event that they are not converted, any outstanding shares are redeemable by the Trust for units on or after February 1, 2004 until February 1, 2010. The ARL Exchangeable Shares are publicly traded.

ARL EXCHANGEABLE SHARES	**2005**	2004
Balance, beginning of year	**1,784**	2,011
Exchanged for trust units	**(189)**	(227)
Balance, end of year	**1,595**	1,784
Exchange ratio, end of year	**1.83996**	1.67183
Trust units issuable upon conversion, end of year	**2,935**	2,982

The non-controlling interest on the consolidated balance sheet consists of the fair value of the exchangeable shares upon issuance plus the accumulated earnings attributable to the non-controlling interest. The net income attributable to the non-controlling interest on the consolidated statement of income represents the cumulative share of net income attributable to the non-controlling interest based on the units issuable for exchangeable shares in proportion to total units issued and issuable at each period end.

Following is a summary of the non-controlling interest for 2005 and 2004:

	2005	2004
Non-controlling interest, beginning of year	**$ 35,967**	$ 36,311
Reduction of book value for conversion to trust units	**(4,018)**	(4,295)
Current period net income attributable to non-controlling interest	**5,545**	3,951
Non-controlling interest, end of year	**$ 37,494**	$ 35,967
Accumulated earnings attributable to non-controlling interest	**$ 20,684**	$ 15,139

13. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

Cash distributions are calculated in accordance with the Trust Indenture. To arrive at cash distributions, cash flow from operating activities adjusted for changes in non-cash working capital and expenditures on site restoration and reclamation, is reduced by reclamation fund contributions including interest earned on the fund and a portion of capital expenditures. The portion of cash flow withheld to fund capital expenditures is at the discretion of the Board of Directors.

	2005	2004
Cash flow from operating activities	**$ 616,711**	$ 446,418
Change in non-cash working capital	**17,919**	(1,617)
Expenditures on site reclamation and restoration	**4,881**	3,232
Cash flow from operating activities after the above adjustments	**$ 639,511**	$ 448,033
Deduct:		
Cash withheld to fund current period capital expenditures	**(256,104)**	(110,846)
Reclamation fund contributions and interest earned on fund	**(6,841)**	(7,210)
Cash distributions (1)	**376,566**	329,977
Accumulated cash distributions, beginning of year	**1,298,252**	968,275
Accumulated cash distributions, end of year	**$ 1,674,818**	$ 1,298,252
Cash distributions per unit (2)	**$ 1.99**	$ 1.80
Accumulated cash distributions per unit, beginning of year	**14.24**	12.44
Accumulated cash distributions per unit, end of year	**$ 16.23**	$ 14.24

(1) Cash distributions include non-cash amounts of $58.3 million ($28 million – 2004). These amounts relate to the distribution reinvestment program.
(2) Cash distributions per unit reflect the sum of the per unit amounts declared monthly to unitholders.

14. TRUST UNIT INCENTIVE RIGHTS PLAN

The Trust Unit Incentive Rights Plan (the "Rights Plan") was established in 1999 that authorized the Trust to grant up to 8,000,000 rights to its employees, independent directors and long-term consultants to purchase units, of which 7,866,088 were granted to December 31, 2005. The initial exercise price of rights granted under the Rights Plan may not be less than the current market price of the units as at the date of grant and the maximum term of each right is not to exceed 10 years. In general, these rights have a five year term and vest equally over three years commencing on the first anniversary date of the grant. In addition, the exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceeds 2.5 per cent (10 per cent annually) of the Trust's net book value of property, plant and equipment (the "Excess Distribution"), as determined by the Trust.

During the year, the Trust did not grant any rights (27,000 rights granted in 2004 at an exercise price of $15.42 per unit). No future rights will be issued as the rights plan was replaced with a Whole Unit Plan during 2004 (see Note 15). The existing Rights Plan will be in place until the remaining 1.3 million rights outstanding as at December 31, 2005 are exercised or cancelled.

A summary of the changes in rights outstanding under the Rights Plan is as follows:

	2005		2004	
	Number of Rights	**Weighted Average Exercise Price** ($)	Number of Rights	Weighted Average Exercise Price ($)
Balance, beginning of year	**3,009**	**10.92**	4,869	11.29
Granted	**–**	**–**	27	15.42
Exercised	**(1,500)**	**11.60**	(1,751)	10.57
Cancelled	**(160)**	**10.99**	(136)	11.60
Balance before reduction of exercise price	**1,349**	**11.10**	3,009	11.72
Reduction of exercise price (1)	**–**	**(0.88)**	–	(0.80)
Balance, end of year	**1,349**	**10.22**	3,009	10.92

(1) The holder of the right has the option to exercise rights held at the original grant price or a reduced exercise price.

A summary of the plan as at December 31, 2005 is as follows:

Exercise Price at Grant Date ($)	Adjusted Exercise Price ($)	Number of Rights Outstanding	Remaining Contractual Life of Rights (years)	Number of Rights Exercisable
12.25	9.00	32	1.4	33
12.49	12.23	118	2.5	118
12.18	10.19	1,172	3.4	399
15.42	14.21	27	4.2	9
12.27	10.22	1,349	3.3	559

The Trust recorded compensation expense of $6.5 million for the year ($5.2 million in 2004) for the cost associated with the rights. Of the 3,013,569 rights issued on or after January 1, 2003 that were subject to recording compensation expense, 355,499 rights have been cancelled and 1,458,929 rights have been exercised to December 31, 2005.

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights issued on or after January 1, 2003. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2004:

	2004
Expected annual right's exercise price reduction	0.72
Expected volatility	13.2%
Risk-free interest rate	3.7%
Expected life of option (years)	1.1
Expected forfeitures	0%

Prior to 2004, the Trust recorded compensation expense on its Rights Plan using the intrinsic method. In 2004, the Trust adopted the fair value method. Use of the fair value prior to 2004 would have resulted in an immaterial impact to the Trust.

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

	2005	2004
Balance, beginning of year	**$ 6,475**	$ 3,471
Compensation expense	**6,524**	5,171
Net benefit on rights exercised (1)	**(6,617)**	(2,167)
Balance, end of year	**$ 6,382**	$ 6,475

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

Compensation expense has not been recorded for rights granted prior to 2003. The following table represents the pro forma net income and the pro forma net income per unit had the Trust applied the fair value method to rights granted in 2002.

Pro Forma Results	**2005**	2004
Net income as reported	**$ 356,935**	$ 241,690
Less: compensation expense for rights issued in 2002	**6,599**	3,189
Pro forma net income	**$ 350,336**	$ 238,501
Basic net income per trust unit		
As reported	**$ 1.90**	$ 1.32
Pro forma	**$ 1.86**	$ 1.30
Diluted net income per trust unit		
As reported	**$ 1.88**	$ 1.31
Pro forma	**$ 1.85**	$ 1.29

15. WHOLE TRUST UNIT INCENTIVE PLAN

In March 2004, the Board of Directors, upon recommendation of the Human Resources and Compensation Committee, approved a new Whole Trust Unit Incentive Plan (the "Whole Unit Plan") to replace the existing Trust Unit Incentive Rights Plan for new awards granted subsequent to March 31, 2004. The new Whole Unit Plan will result in employees, officers and directors (the "plan participants") receiving cash compensation in relation to the value of a specified number of underlying notional units. The Whole Unit Plan consists of Restricted Trust Units ("RTUs") for which the number of trust units is fixed and will vest over a period of three years and Performance Trust Units ("PTUs") for which the number of trust units is variable and will vest at the end of three years.

Upon vesting, the plan participant receives a cash payment based on the fair value of the underlying trust units plus notional accrued distributions. The cash compensation issued upon vesting of the PTUs is dependent upon the future performance of the Trust compared to its peers based on a performance multiplier. The performance multiplier is based on the percentile rank of the Trust's total unitholder return. The cash compensation issued upon vesting of the PTUs may range from zero to two times the number of the PTUs originally granted.

The fair value associated with the RTUs and PTUs is expensed in the statement of income over the vesting period. As the value of the RTUs and PTUs is dependent upon the unit price, the expense recorded in the statement of income may fluctuate over time.

The Trust recorded compensation expense of $8.8 million and $1.9 million to general and administrative and operating expenses, respectively in 2005 ($2.9 million and $nil in 2004) for the estimated cost of the plan. The compensation expense was based on the December 31, 2005 unit price of $26.49 ($17.90 in 2004), distributions of $0.20 per unit per month during the year ($0.15 per month in 2004), and the number of units to be issued on maturity.

	2005		2004	
	Number of RTUs	**Number of PTUs**	Number of RTUs	Number of PTUs
Balance, beginning of year	**224,398**	**128,331**	–	–
Vested	**(78,745)**	**–**		
Granted	**367,030**	**304,655**	226,837	128,908
Forfeited	**(33,918)**	**(42,429)**	(2,439)	(577)
Balance, end of year	**478,765**	**390,557**	224,398	128,331

The following table reconciles the change in total accrued compensation liability relating to the Whole Unit Plan:

	December 31, 2005	December 31, 2004
Balance, beginning of year	**$ 2,915**	$ –
Increase in liabilities in the year (net of cash payments)		
General and administrative expense	**8,774**	2,915
Operating expense	**1,916**	–
Property, plant and equipment	**1,352**	–
Balance, end of year	**$ 14,957**	$ 2,915
Current portion of liability	**3,597**	1,022
Long-term liability	**$ 11,360**	$ 1,893

During the year $1.6 million in cash payments were made to employees relating to the Whole Unit Plan (2004 – $nil).

16. BASIC AND DILUTED PER TRUST UNIT CALCULATIONS

Net income per unit has been determined based on the following:

	2005	2004
Weighted average trust units (1)	**188,237**	183,123
Trust units issuable on conversion of exchangeable shares (2)	**2,935**	2,982
Dilutive impact of rights (3)	**1,372**	1,756
Dilutive trust units and exchangeable shares	**192,544**	187,861

(1) Weighted average units excludes units issuable for exchangeable shares.
(2) Diluted units include units issuable for outstanding exchangeable shares at the period end exchange ratio.
(3) All outstanding rights were dilutive and therefore none have been excluded in the diluted unit calculation.

Basic net income per unit has been calculated based on net income after non-controlling interest divided by weighted average units. Diluted net income per unit has been calculated based on net income before non-controlling interest divided by dilutive units.

17. GAIN (LOSS) ON FOREIGN EXCHANGE

The following is a summary of the gain (loss) on commodity and foreign currency contracts for 2005:

	2005	2004
Unrealized (loss) gain on US$ denominated debt	**$ (4,221)**	$ 21,922
Realized gain (loss) on US$ denominated debt repayments	**10,580**	(3,495)
Total non-cash gain on US$ denominated transactions	**$ 6,359**	$ 18,427
Realized cash gain on US$ denominated transactions	**53**	2,286
Total foreign exchange gain	**$ 6,412**	$ 20,713

18. COMMITMENTS AND CONTINGENCIES

Following is a summary of the Trust's contractual obligations and commitments as at December 31, 2005:

	Payments Due By Period				
($ millions)	2006	2007-2008	2009-2010	Thereafter	Total
Debt repayments (1)	–	279.4	49.2	198.0	526.6
Reclamation fund contributions (2)	6.1	11.8	10.2	80.9	109.0
Purchase commitments	2.4	3.4	3.2	8.0	17.0
Operating leases	4.1	8.1	7.3	–	19.5
Derivative contract premiums (3)	12.4	–	–	–	12.4
Retention bonuses	1.0	1.0	–	–	2.0
Total contractual obligations	26.0	303.7	69.9	286.9	686.5

(1) Includes long-term and short-term debt.
(2) Contribution commitments to a restricted reclamation fund associated with the Redwater property acquired in the Redwater and NPCU acquisition.
(3) Fixed premiums to be paid in future periods on certain commodity derivative contracts.

The Trust enters into commitments for capital expenditures in advance of the expenditures being made. At a given point in time, it is estimated that the Trust has committed to capital expenditures by means of giving the necessary authorizations to incur capital in a future period. This commitment has not been disclosed in the above commitment table as it is of a routine nature and is part of normal course of operations for active oil and gas companies and trusts.

Other items excluded from the commitment table above include commitments regarding asset retirement obligations and the Whole Unit Plan. These amounts have been accrued for, however, the final payment amounts are uncertain and are therefore excluded above.

The Trust has certain sales contracts with aggregators whereby the price received by the Trust is dependent upon the contracts entered into by the aggregator. The Trust has an obligation for future fixed transportation charges, pursuant to one aggregator contract, for which the transportation is not physically being utilized due to a shortage of demand. The Trust has estimated that its total future liability for the future transportation charges approximates $10 million over the period 2006 through 2012. This transportation charge will be realized as a reduction of the Trust's net gas price over the corresponding period as the charges are incurred. For all other aggregator contracts, prices received by the Trust closely track to market prices.

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the Trust's financial position or reported results of operations.

In addition to the above, the Trust has commitments related to its risk management program (see Note 9).

19. SUBSEQUENT EVENTS

FINANCIAL WTI CRUDE OIL CONTRACTS

On January 12, 2006, the Trust entered into a series of $55 – $90 ($40) 3-way collars for the period February 2006 to December 2009 for 5,000 bbl per day. The contracts will result in a $7.5 million premium payment during the duration of the contracts.

PROPERTY ACQUISITIONS

During January 2006, the Trust acquired property, plant, and equipment for consideration of $26 million.

20. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP, which differs in some respects from US GAAP. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements are immaterial except as described below:

The application of US GAAP would have the following effect on net income as reported.

	2005	2004
Net income as reported for Canadian GAAP	**$ 356,935**	$ 241,690
Adjustments:		
Depletion and depreciation (a)	**15,639**	19,004
Unrealized gain on derivative instruments (c)	**–**	13,721
Unit based compensation (b)	**(7,274)**	(9,219)
Non-controlling interest (e)	**5,545**	3,951
Effect of applicable income taxes on the above adjustments	**(5,357)**	(2,142)
Net income under US GAAP	**$ 365,488**	$ 267,005
Net income per trust unit (Note 16)		
Basic (f)	**$ 1.91**	$ 1.43
Diluted (f)	**$ 1.90**	$ 1.42
Comprehensive income:		
Net income under US GAAP	**$ 365,488**	$ 267,005
Unrealized gain (loss) on derivative instruments, net of applicable income taxes	**1,593**	(2,441)
Comprehensive income (c)	**$ 367,081**	$ 264,564

The application of US GAAP would have the following effect on the consolidated balance sheets as reported:

	2005		2004	
	Canadian GAAP	**US GAAP**	Canadian GAAP	US GAAP
Property, plant and equipment	**$ 2,929,977**	**$ 2,797,398**	$ 2,016,646	$ 1,868,428
Commodity and foreign currency contracts	**(4,042)**	**(5,261)**	(4,042)	(7,685)
Future income taxes	**(515,877)**	**(491,831)**	(300,406)	(270,173)
Non-controlling interest (e)	**(37,494)**	**–**	(35,967)	–
Temporary equity (d)	**–**	**(5,077,983)**	–	(3,379,594)
Unitholders' capital	**(2,230,842)**	**–**	(1,926,351)	–
Contributed surplus	**(6,382)**	**–**	(6,475)	–
Accumulated earnings	**(1,235,742)**	**1,676,473**	(878,807)	651,227
Accumulated other comprehensive loss	**–**	**802**	–	2,395

The above noted differences between Canadian GAAP and US GAAP are the result of the following:

(a) The Trust performs an impairment test that limits net capitalized costs to the discounted estimated future net revenue from proved and risked probable oil and natural gas reserves plus the cost of unproved properties less impairment, using forward prices. For Canadian GAAP the discount rate used must be equal to a risk free interest rate. Under US GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount rate of 10 per cent. Prices used in the US GAAP ceiling tests are those in effect at year end. The amounts recorded for depletion and depreciation have been adjusted in the periods following the additional write-downs taken under US GAAP to reflect the impact of the reduction of depletable costs.

(b) For US GAAP purposes, the Rights Plan has been accounted for as a variable compensation plan as the exercise price of the rights is subject to downward revisions from time to time. Accordingly, compensation expense is determined as the excess of the market price over the adjusted exercise price of the rights at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. After the rights have vested, compensation expense is recognized in income in the period in which a change in the market price of the units or the exercise price of the rights occurs. Canadian GAAP requires that all unit-based compensation plans be fair valued. As such, an adjustment to earnings has been recorded to reflect the additional compensation expense on rights issued prior to January 1, 2003 for US GAAP purposes and for the difference between the intrinsic value and the fair value of rights issued since that time which are still outstanding at December 31, 2005.

(c) US GAAP requires that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded on the consolidated balance sheet as either an asset or liability measured at fair value and requires that changes in fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs, and requires that a company formally document, designate, and assess the effectiveness of derivative instruments that receive hedge accounting treatment. Under Canadian GAAP, derivative instruments that meet these specific hedge accounting criteria are not recorded on the consolidated balance sheet. In addition, unrealized gains and losses on effective hedges are not recorded in the financial statements. The Trust formally documented and designated all hedging relationships and verified that its hedging instruments were effective in offsetting changes in actual prices and rates received by the Trust. Hedge effectiveness is monitored and any ineffectiveness is reported in the consolidated statement of income.

A reconciliation of the components of accumulated other comprehensive income related to all derivative positions is as follows:

	2005		2004	
	Gross	**After Tax**	Gross	After Tax
Accumulated other comprehensive (loss) income, beginning of year	**$ (3,643)**	**$ (2,395)**	$ 78	$ 46
Effect of change in corporate tax rate	**–**	**–**	–	(5)
Reclassification of net realized gains into earnings	**(799)**	**(529)**	(969)	(637)
Net change in fair value of derivative instruments	**3,223**	**2,122**	(2,752)	(1,799)
Accumulated other comprehensive loss, end of year	**$ (1,219)**	**$ (802)**	$ (3,643)	$ (2,395)

(d) Under US GAAP, as the units are redeemable at the option of the unitholder, the units must be valued at their redemption amount and presented as temporary equity in the consolidated balance sheet. The redemption value of the units is determined with respect to the trading value of the units and the unit equivalent of the exchangeable shares at each balance sheet date. Under Canadian GAAP, all units are classified as permanent equity. As at December 31, 2005 and 2004, the Trust has classified $5.1 billion and $3.4 billion, respectively, as temporary equity in accordance with US GAAP. Changes in redemption value between periods are charged or credited to accumulated earnings.

(e) Under Canadian GAAP, ARL Exchangeable Shares are classified as non-controlling interest to reflect a minority ownership in one of the Trust's subsidiaries. As these exchangeable shares must ultimately be converted into units, the exchangeable shares are classified as temporary equity along with the units for US GAAP purposes.

(f) Under Canadian GAAP, basic net income per unit is calculated based on net income after non-controlling interest divided by weighted average units and diluted net income per unit is calculated based on net income before non-controlling interest divided by dilutive units. Under US GAAP, as the exchangeable shares are classified in the same manner as the units with no non-controlling interest treatment, basic net income per unit is calculated based on net income divided by weighted average units and the unit equivalent of the outstanding exchangeable shares. Concurrently, diluted net income per unit is calculated based on net income divided by a sum of the weighted average units, the unit equivalent of the outstanding exchangeable shares, and the dilutive impact of rights.

(g) In 2005 and 2004, the FASB and the CICA issued new and revised standards, all of which were assessed by management to be not applicable to the Trust with the exception of the following:

- In December 2004, the FASB Issued SFAS No. 123R, "Share Based Payments", which addresses the issue of measuring compensation cost associated with Share Based Payment plans. This statement requires that all such plans, for public entities, be measured at fair value using an option pricing model whereas previously certain plans could be measured using either a fair value method or an intrinsic value method. The revision is intended to increase the consistency and comparability of financial results by only allowing one method of application. This revised standard is effective fiscal year 2006. The Trust will adopt SFAS 123R on January 1, 2006 and will determine the impact in 2006.
- In 2004, FASB issued FAS 153 "Exchange of Non-monetary Assets". This statement is an amendment of APB Opinion No. 29 "Accounting for Non-monetary Transactions". Based on the guidance in APB Opinion No. 29, exchanges of non-monetary assets are to be measured based on the fair value of the assets exchanged. Furthermore, APB Opinion No. 29 previously allowed for certain exceptions to this fair value principle. FAS 153 eliminates APB Opinion No. 29's exception to fair value for non-monetary exchanges of similar productive assets and replaces this with a general exception for exchanges of non-monetary assets which do not have commercial substance. For purposes of this statement, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges which occur in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. Earlier

application is permitted for non-monetary asset exchanges which occur in fiscal periods beginning after the issue date of this statement. Currently, this statement does not have an impact on the Trust; however, this may result in a future impact to the Trust if it enters into any non-monetary asset exchanges.

- In May 2005, FASB issued FAS 154, "Accounting Changes in Error Corrections", changes the requirements for the accounting for and reporting of a change in accounting principle. The standard is effective for the Trust in fiscal 2006
- In January 2005, the CICA approved Handbook Section 1530, "Comprehensive Income". The new standard is intended to harmonize Canadian GAAP with US GAAP. The new standard is effective for the Trust in the first quarter of 2007.