PENGROWTH ENERGY TRUST
Form 6-K
March 01, 2006

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 6-K
Report of Foreign Private Issuer
Pursuant to Rule 13a-16 or 15d-16 of the
Securities Exchange Act of 1934
For the period February 24, 2006 to February 28, 2006
PENGROWTH ENERGY TRUST
2900, 240 4th Avenue S.W.
Calgary, Alberta T2P 4H4 Canada
(address of principal executive offices)

[Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.]

Form 20-F o Form 40-F þ

[Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Security Exchange Act of 1934.

Yes o No þ

[If Yes is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b):__________]

DOCUMENTS FURNISHED HEREUNDER:

1. Press Release announcing unaudited financial, operating and reserve results for year ended December 31, 2005.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENGROWTH ENERGY TRUST
by its administrator PENGROWTH CORPORATION

February 28, 2006

By: /s/ Gordon M. Anderson

Name: Gordon M. Anderson
Title: Vice President

NEWS RELEASE

Attention: Financial Editors **Stock Symbol:** **(PGF.A / PGF.B) TSX; (PGH) NYSE**

PENGROWTH ENERGY TRUST ANNOUNCES UNAUDITED FINANCIAL, OPERATING AND RESERVE RESULTS FOR YEAR ENDED DECEMBER 31, 2005

(**Calgary** February 27, 2006) /CCN Matthews/ Pengrowth Corporation, administrator of Pengrowth Energy Trust, is pleased to report operating and financial results for the fourth quarter and year ended December 31, 2005 as well as selected information from Pengrowth s independent engineering reserve report effective December 31, 2005.

YEAR 2005 OVERVIEW

Robust commodity prices, a full year of production from the 2004 Murphy acquisition and additional production from the Swan Hills Unit No.1 (Swan Hills) and Crispin Energy Inc. (Crispin) acquisitions, which closed on February 28, 2005 and April 29, 2005, respectively, combined to have a favorable impact on 2005 financial and operating results relative to 2004.

2005 KEY ACHIEVEMENTS AND MILESTONES

- Oil and gas sales increased 41 percent to $1.15 billion in 2005 resulting in record net income of $326 million, an increase of 112 percent over 2004.

- Production for 2005 averaged 59,357 barrels of oil equivalent (boe) per day, an increase of ten percent versus 2004. Fourth quarter production averaged 61,442 boe per day, an increase of four percent over the previous quarter and seven percent over the comparable period in 2004.

- Distributable cash reached a new high in 2005 at $620 million, an increase of 54 percent over 2004. Fourth quarter distributable cash increased 87 percent versus 2004 to $196 million, the highest level of distributable cash generated in any quarter in Pengrowth s history.

- Distributions paid or declared to unitholders increased 23 percent to $446 million or $2.82 per trust unit in 2005 from $363 million or $2.63 per trust unit in 2004. Pengrowth s monthly distribution was increased in December 2005 to an annualized rate of $3.00 per trust unit.

- Pengrowth s payout ratio to unitholders for the full year and fourth quarter of 2005 reached record lows of 72 percent and 61 percent of cash generated from operations, respectively.

- Pengrowth s 2005 development expenditures were essentially fully funded through the withholdings from distributable cash.

- During the year Pengrowth spent a combined total of $176 million on maintenance and development projects ending the year with proved plus probable reserves of 219.4 million barrels of oil equivalent (mmboe) compared to 218.6 mmboe at year-end 2004. Pengrowth s proved plus probable reserves were replaced through the addition of 16.7 mmboe related to acquisitions and 8.6 mmboe resulting from drilling activity, improved recoveries and technical revisions. Additions were offset by production of 21.7 mmboe and divestures of 2.8 mmboe.

- During 2005, Pengrowth incurred Finding and Development (F&D) costs for proved reserves of $10.63 per boe, including the change in future development capital, in accordance with NI 51-101. Excluding the downward revision to future development capital of approximately $37 million, Pengrowth s F&D costs for proved reserves totaled $15.47 per boe during 2005. Overall finding, development and acquisition (FD&A) costs, with and without the change in future development capital, were $14.42 per boe and $16.12 per boe, respectively.

- Pengrowth s average realized commodity price (after hedging) increased 28 percent to $53.02 per boe in 2005, from $41.33 in 2004.

- Operating netbacks increased 33 percent to $32.54 per boe (after hedging) versus $24.51 per boe in 2004. Combined hedging losses totaled $3.04 per boe in 2005 versus $3.52 per boe in 2004.

- On February 28, 2005, Pengrowth acquired an additional 11.9 percent working interest in the Swan Hills property for $87 million. This acquisition increased Pengrowth s total interest in the property to 22.3 percent.

- On April 29, 2005, Pengrowth successfully completed the acquisition of all of the issued and outstanding shares of Crispin, adding approximately 1,900 boe per day of production to our portfolio.

- On December 1, 2005, Pengrowth completed a £50 million private placement of senior unsecured ten year notes.

- As at December 31, 2005, Pengrowth had $337 million of funds available under its $370 million in committed credit facilities.

- As at December 31, 2005, Pengrowth had generated a combined three-year weighted average compound total return of 36 percent per annum for Class A and Class B unitholders.

The following table and discussion includes non-GAAP financial measures. Certain non-GAAP financial measures are used to facilitate the evaluation of underlying trends that can be compared with prior periods and may not be comparable to results presented by other companies (see Non-GAAP Financial Measures).

Summary of Financial and Operating Results

(thousands, except per unit amounts)	Three Months ended December 31 2005	Three Months ended December 31 2004	% Change	Twelve Months ended December 31 2005	Twelve Months ended December 31 2004	% Change
INCOME STATEMENT						
Oil and gas sales	$ 353,923	$ 223,183 **	59%	$ 1,151,510	$ 815,751 **	41%
Net income	$ 116,663	$ 31,138	275%	$ 326,326	$ 153,745	112%
Net income per trust unit	$ 0.73	$ 0.23	217%	$ 2.08	$ 1.15	81%
Cash generated from operations	$ 196,588	$ 93,287	111%	$ 618,070	$ 404,167	53%
Cash generated from operations per trust unit	$ 1.23	$ 0.68	81%	$ 3.93	$ 3.03	30%
Distributable cash *	$ 195,879	$ 104,958 **	87%	$ 619,739	$ 401,178 **	54%
Distributable cash per trust unit *	$ 1.23	$ 0.77	60%	$ 3.94	$ 3.01	31%
Distributions paid or declared	$ 119,858	$ 96,466	24%	$ 445,977	$ 363,061	23%
Distributions paid or declared per unit	$ 0.75	$ 0.69	9%	$ 2.82	$ 2.63	7%
Weighted average number of trust units outstanding	159,528	136,916	17%	157,127	133,395	18%
BALANCE SHEET						
Working capital				$ (112,205)	$ (78,546)	43%
Property, plant and equipment and other assets				$ 2,067,988	$ 1,989,288	4%
Long term debt				$ 368,089	$ 345,400	7%
Unitholders equity				$ 1,475,996	$ 1,462,211	1%
Unitholders equity per trust unit				$ 9.23	$ 9.56	-3%
Number of trust units outstanding at year-end				159,864	152,973	5%
Daily Production						
Crude oil (barrels)	21,179	20,118	5%	20,799	20,817	0%
Heavy oil (barrels)	5,410	5,819	-7%	5,623	3,558	58%
Natural gas (mcf)	168,862	156,621	8%	161,056	144,277	12%
Natural gas liquids (barrels)	6,710	5,385	25%	6,093	5,281	15%
Total production (boe)	61,442	57,425	7%	59,357	53,702	10%
Total Production (mboe)	5,653	5,283	7%	21,665	19,655	10%
Production Profile						
Crude oil	34%	35%		35%	39%	
Heavy oil	9%	10%		10%	6%	
Natural gas	46%	46%		45%	45%	
Natural gas liquids	11%	9%		10%	10%	
Average Realized Prices (after hedging)						
Crude oil (per barrel)	$ 59.40	$ 44.76	33%	$ 58.59	$ 43.21	36%

Heavy oil (per barrel)	$	31.77	$	26.99	18%	$	33.32	$	32.45	3%
Natural gas (per mcf)	$	11.97	$	7.02	71%	$	8.76	$	6.80	29%
Natural gas liquids (per barrel)	$	58.46	$	48.04	22%	$	54.22	$	42.21	28%
Average realized price per boe	$	62.55	$	42.08 **	49%	$	53.02	$	41.33 **	28%
Proved Plus Probable (P50) Reserves										
Crude oil (mbbls)							98,684		94,066	5%
Heavy oil (mbbls)							15,790		18,245	-13%
Natural gas (bcf)							516		521	-1%
Natural gas liquids (mbbls)							18,985		19,395	-2%
Total oil equivalent (mboe)							219,396		218,613	0%

* See the section entitled Non-GAAP Financial Measures

** Restated to conform to presentation adopted in the current year

Frequently Recurring Terms

For the purposes of this release, we use certain frequently recurring terms as follows: the Trust refers to Pengrowth Energy Trust, the Corporation refers to Pengrowth Corporation, Pengrowth refers to the Trust and the Corporation on a consolidated basis and the Manager refers to Pengrowth Management Limited.

Advisory Regarding Forward-Looking Statements

This release contains forward-looking statements within the meaning of securities laws, including the safe harbour provisions of the Ontario *Securities Act* and the United States *Private Securities Litigation Reform Act of 1995*. Forward-looking information is often, but not always, identified by the use of words such as anticipate , believe , expect , plan , intend , forecast , target , project , may , will , should , could , estimate , predict or s future outcomes or language suggesting an outlook. Forward-looking statements in this release include, but are not limited to, statements with respect to: reserves, average 2006 production, production additions from Pengrowth s 2006 development program, the impact on production of divestitures in 2006, total operating cost for 2006, 2006 operating costs per boe, capital expenditures for 2006 and the breakdown of such capital expenditures for drilling, facilities and maintenance, land and seismic acquisition and re-completions, workovers and CO_2 pilot. Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can profitably be produced in the future.

Forward-looking statements and information are based on Pengrowth s current beliefs as well as assumptions made by and information currently available to Pengrowth concerning anticipated financial performance, business prospects, strategies and regulatory developments. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predications, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; Pengrowth s ability to replace and expand oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; compliance with environmental laws and regulations; changes in tax laws; the failure to qualify as a mutual fund trust; and Pengrowth s ability to access external sources of debt and equity capital. Further information regarding these factors may be found in the Supplemental Information section under the heading Business Risks herein and under Risk Factors in Pengrowth s Annual Information Form which will be available on SEDAR at www.sedar.com on or before March 31, 2006.

Pengrowth cautions that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Pengrowth, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Furthermore, the forward-looking statements contained in this release are made as of the date of the release and Pengrowth does not undertake any obligation to up-date publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this release are expressly qualified by this cautionary statement.

Critical Accounting Estimates

As discussed in Note 2 to the financial statements, the financial statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended.

The amounts recorded for depletion, depreciation and amortization of injectants and the provision for asset retirement obligations are based on estimates. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. As required by National Instrument 51-101 (NI 51-101), Pengrowth uses independent qualified reserve evaluators in the preparation of reserve evaluations. By their nature, these estimates are subject to measurement uncertainty and changes in these estimates may impact the consolidated financial statements of future periods.

Non-GAAP Financial Measures

This release refers to certain financial measures that are not determined in accordance with GAAP in Canada or the United States. These measures do not have standardized meanings and may not be comparable to similar measures presented by other trusts or corporations. Measures such as distributable cash, distributable cash per trust unit, payout ratio and operating netbacks do not have standardized meanings prescribed by GAAP. During the second quarter of 2005, Pengrowth s withholding practice and presentation of distributable cash changed. The impact of the new practice is discussed in the Distributable Cash, Distributions and Taxability of Distributions section of this release, while the remaining non-GAAP measures are determined by reference to our financial statements. We discuss these measures because we believe that they facilitate the understanding of the results of our operations and financial position.

Conversion and Currency

When converting natural gas to equivalent barrels of oil within this release, Pengrowth uses the international standard of six thousand cubic feet (mcf) to one barrel of oil equivalent. Barrels of oil equivalent may be misleading, particularly if used in isolation; a conversion ratio of six mcf of natural gas to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Production volumes, revenues and reserves are reported on a company interest gross basis (before royalties) in accordance with Canadian practice. All amounts are stated in Canadian dollars unless otherwise specified.

RESULTS OF OPERATIONS

Production

Average daily production increased over ten percent in 2005 compared to 2004. The increase is attributable primarily to the Murphy, Swan Hills and Crispin acquisitions and contributions from ongoing development activities. At this time, Pengrowth is forecasting average 2006 production of 54,000 to 56,000 boe per day from existing assets. This estimate incorporates anticipated production additions from planned 2006 development activities. Offsetting these additions are previously disclosed divestitures of approximately 1,300 boe per day in the first quarter of 2006 which have been excluded from the above estimate, including the divestment of approximately 1,000 boe per day related to the Monterey Exploration Ltd. (Monterey) transaction announced on January 12, 2006 and expected production declines from normal operations. The above estimate specifically excludes the potential impact of any other future acquisitions or divestitures.

	Three months ended	Twelve months ended

(1) bbls refers to barrels

Light crude oil production volumes remained relatively flat year-over-year due to the positive impact of production related to the Swan Hills and Crispin acquisitions which largely offset natural production declines. Improved miscible flood response at Judy Creek contributed to most of the three percent increase in production in fourth quarter 2005 versus the third quarter of 2005.

Heavy oil production increased 58 percent year-over-year due to the inclusion of a full 12 months of production volumes from properties acquired in the Murphy acquisition which closed on May 31, 2004. The seven percent decrease in production for the fourth quarter of 2005 compared to the fourth quarter of 2004 is attributable to natural production declines.

Natural gas production increased 12 percent year-over-year. Additional production volumes from the Murphy and Crispin acquisitions and ongoing development activities, particularly the Monogram infill drilling program completed in the fourth quarter of 2004, combined to more than offset natural production declines. The three percent increase in volumes in the fourth quarter of 2005 compared to the third quarter of 2005 is due largely to a 44 well drilling program at Princess which was completed during the fourth quarter. Fourth quarter 2005 volumes were eight percent higher than fourth quarter 2004 volumes primarily due to the Crispin acquisition, new wells at Princess and Sable Offshore Energy Project (SOEP) and lower residue gas solvent demand at Judy Creek allowing for increased sales.

Natural gas liquids (NGL) production increased 15 percent year-over-year primarily due to the timing and size of condensate sales from SOEP. Pengrowth received six shipments from SOEP in 2005 (two shipments in the fourth quarter) compared to four shipments in the previous year.

Pricing and Commodity Price Hedging

The increase in U.S. based prices for North American crude oil and natural gas was partially offset by the negative impact of the rising Canadian dollar relative to the U.S. dollar and hedging losses.

	Three months ended			Twelve months ended	
	Dec 31, 2005	Sept 30, 2005	Dec 31, 2004	**Dec 31, 2005**	Dec 31, 2004
Average realized prices (Cdn$)					
Light crude oil (per bbl)	**67.00**	74.37	55.24	**65.47**	50.72
after hedging	**59.40**	63.95	44.76	**58.59**	43.21
Heavy oil (per bbl)	**31.77**	47.74	26.99	**33.32**	32.45
Natural gas (per mcf)	**12.80**	8.69	7.25	**8.99**	7.03
after hedging	**11.97**	8.57	7.02	**8.76**	6.80
Natural gas liquids (per bbl)	**58.46**	57.75	48.04	**54.22**	42.21
Total per boe	**67.43**	60.06	46.38	**56.06**	44.85
after hedging	**62.55**	56.07	42.08	**53.02**	41.33
Benchmark prices					
WTI oil (U.S.$ per bbl)	**60.05**	63.31	48.27	**56.70**	41.47
AECO spot gas (Cdn$ per gj) (1)	**11.08**	7.75	6.72	**8.04**	6.44
NYMEX gas (U.S. $ per mmbtu) (2)	**12.97**	8.49	7.11	**8.62**	6.16
Currency (U.S.$/Cdn $)	**0.85**	0.83	0.82	**0.83**	0.77

(1) gj refers to gigajoules

(2) mmbtu refers to millions of British thermal units

As part of our financial management strategy, Pengrowth uses forward price swap and option contracts to manage its exposure to commodity price fluctuations, to provide a measure of stability to monthly cash distributions and to partially secure returns on significant new acquisitions.

Hedging Losses	Three months ended Dec 31, 2005	Sept 30, 2005	Dec 31, 2004	Twelve months ended Dec 31, 2005	Dec 31, 2004
Light crude oil ($ million)	**14.8**	19.8	19.4	**52.2**	57.2
Light crude oil ($ per bbl)	**7.60**	10.42	10.48	**6.88**	7.51
Natural gas ($ million)	**12.9**	1.8	3.3	**13.6**	11.9
Natural gas ($ per mcf)	**0.83**	0.12	0.23	**0.23**	0.23
Combined ($ million)	**27.7**	21.6	22.7	**65.8**	69.1
Combined ($ per boe)	**4.88**	3.99	4.30	**3.04**	3.52

Commodity price hedges in place at December 31, 2005 are provided in Note 17 to the financial statements. Pengrowth has not entered into any additional contracts subsequent to year-end as of February 27, 2006.

In conjunction with the Murphy acquisition, Pengrowth assumed certain fixed price natural gas sales contracts and firm pipeline demand charge contracts associated with the Murphy reserves. Under these contracts, Pengrowth is obligated to sell 3,886 mmbtu per day, until April 30, 2009 at an average remaining contract price of Cdn $2.31 per mmbtu. As required by GAAP, the fair value of the natural gas sales contract was recognized as a liability based on the mark-to-market value at May 31, 2004. The liability at December 31, 2005 of $18.2 million for the contracts will continue to be drawn down and recognized in income as the contracts are settled. As this is a non-cash component of income, it is not included in the calculation of distributable cash. At December 31, 2005, the mark-to-market value of the fixed price physical sales contract represented a potential loss of $35.3 million.

Oil and Gas Sales Contribution Analysis

Sales Revenue ($ million)	Three months ended Dec 31, 2005	% of total	Sept 30, 2005	% of total	Dec 31, 2004	% of total	Twelve months ended Dec 31, 2005	% of total	Dec 31, 2004	% of total
Natural gas	**186.0**	**53%**	129.5	43%	101.2	45%	**514.9**	**45%**	359.3	44%
Light crude oil	**115.7**	**33%**	121.6	40%	82.8	37%	**444.8**	**39%**	329.2	40%
Natural gas liquids	**36.1**	**10%**	28.9	9%	23.8	11%	**120.6**	**10%**	81.6	10%
Heavy oil	**15.8**	**4%**	23.7	8%	14.5	7%	**68.4**	**6%**	42.3	5%
Brokered sales/sulphur	**0.3**	**0%**	0.8	0%	0.9	0%	**2.8**	**0%**	3.4	1%
Total oil and gas sales	**353.9**		304.5		223.2		**1,151.5**		815.8	

Oil and Gas Sales Price and Volumes Analysis

The following table illustrates the effect of changes in prices and volumes on the components of oil and gas sales, including the impact of hedging.

($ million)	Natural gas	Light oil	NGL	Heavy oil	Other	Total

Year ended December 31, 2004	359.3	329.2	81.6	42.3	3.4	815.8
Effect of change in product prices	115.3	112.0	26.7	1.8		255.8
Effect of change in sales volumes	42.0	(1.4)	12.3	24.3		77.2
Effect of hedging losses	(1.7)	5.0				3.3
Other					(0.6)	(0.6)
Year ended December 31, 2005	514.9	444.8	120.6	68.4	2.8	1,151.5

Processing, Interest and Other Income

($ million)	Three months ended **Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	Twelve months ended **Dec 31, 2005**	Dec 31, 2004
Processing, interest & other income	**4.0**	2.1	4.5	**17.7**	14.2
$ per boe	**0.71**	0.39	0.83	**0.82**	0.72

Processing, interest and other income is primarily derived from fees charged for processing and gathering third party gas, road use, and oil and water processing. This income represents the partial recovery of operating costs included below in Operating Expenses.

Royalties

($ million)	Three months ended **Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	Twelve months ended **Dec 31, 2005**	Dec 31, 2004
Royalty expense	**68.0**	57.4	49.1	**213.9**	160.4
$ per boe	**12.03**	10.60	9.29	**9.87**	8.16
Royalties as a percent of sales	**19.2%**	18.9%	22.0%	**18.6%**	19.7%

Royalties include crown, freehold and overriding royalties as well as mineral taxes. A lesser credit for enhanced oil recovery relief at Judy Creek had an unfavorable impact to royalties in the fourth quarter of 2004 as solvent injection costs were lower than anticipated.

Operating Expenses

($ million)	Three months ended **Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	Twelve months ended **Dec 31, 2005**	Dec 31, 2004
Operating expenses	**61.2**	57.4	42.6	**218.1**	159.7
$ per boe	**10.83**	10.59	8.06	**10.07**	8.13

Operating expenses increased year-over-year as a result of timing of acquisitions partway through 2004 and in 2005 which impacted costs by approximately $30 million. Additionally, there was general upward pressure on the cost of goods and services in the oil and gas industry during 2005, with year-over-year increases of more than ten percent within most of these areas. Utility costs also increased approximately $10 million year-over-year. Operating expenses include costs incurred to earn processing and other income included above in Processing, Interest and Other Income.

Transportation Costs

($ million)	Three months ended **Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	Twelve months ended **Dec 31, 2005**	Dec 31, 2004
Light oil transportation	**0.5**	0.6	0.4	**2.2**	1.8
$ per bbl	**0.27**	0.29	0.23	**0.29**	0.23
Natural gas transportation	**1.8**	1.4	2.0	**5.7**	6.3
$ per mcf	**0.12**	0.09	0.14	**0.10**	0.12

Pengrowth incurs transportation costs for its product once the product enters a feeder or main pipeline to the title transfer point. The transportation cost is dependant upon industry rates and distance the product flows on the pipeline prior to changing ownership or custody. Pengrowth has the option to sell some of its natural gas directly to premium markets outside of Alberta by incurring additional transportation costs. In 2005, Pengrowth sold most of its natural gas without incurring significant additional transportation costs. Similarly, Pengrowth has elected to sell approximately 75 percent of its crude oil at market points beyond the wellhead, but at the first major trading point, requiring minimal transportation costs.

Amortization of Injectants for Miscible Floods

	Three months ended			Twelve months ended	
($ million)	**Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	**Dec 31, 2005**	Dec 31, 2004
Purchased and capitalized	**14.5**	6.9	8.2	**34.7**	20.4
Amortization	**7.1**	6.0	4.9	**24.4**	19.7

The cost of injectants (primarily natural gas and ethane) purchased for injection in miscible flood programs is amortized over the period of expected future economic benefit. Prior to 2005, the expected future economic benefit from injection was estimated at 30 months, based on the results of previous flood patterns. Commencing in 2005 the response period for additional new patterns being developed is expected to be somewhat shorter relative to the historical miscible patterns in the project. Accordingly, the cost of injectants purchased in 2005 will be amortized over a 24 month period while costs incurred for the purchase of injectants in prior periods will continue to be amortized over 30 months. As of December 31, 2005, the balance of unamortized injectant costs was $35.3 million.

The value of Pengrowth s proprietary injectants is not recorded until reproduced from the flood and sold, although the cost of producing these injectants is included in operating costs. Pengrowth currently anticipates similar injection volumes for Judy Creek and increased injection volumes for Swan Hills during 2006. This combined with higher forecast prices for natural gas and ethane is anticipated to result in increased total injectant costs for 2006.

Netbacks

There is no standardized measure of operating netbacks and therefore operating netbacks, as presented below may not be comparable to similar measures presented by other companies. Certain assumptions have been made in allocating operating expenses, other production income, other income and royalty injection credits between light crude oil, heavy oil, natural gas and NGL production.

Pengrowth recorded an operating netback of $32.54 per boe (after hedging) in 2005 compared to $24.51 (after hedging) in 2004, mainly due to higher average commodity prices in 2005 partially offset by higher operating costs and royalties.

	Three months ended			Twelve months ended	
Combined Netbacks ($ per boe)	**Dec 31, 2005**	**Sept 30, 2005**	**Dec 31, 2004**	**Dec 31, 2005**	**Dec 31, 2004**
Sales price	$ 62.55	$ 56.07	$ 42.08	$ 53.02	$ 41.33
Other production income	0.06	0.13	0.17	0.13	0.17
	62.61	56.20	42.25	53.15	41.50
Processing, interest and other income	0.71	0.39	0.83	0.82	0.72
Royalties	(12.02)	(10.60)	(9.29)	(9.87)	(8.16)
Operating costs	(10.83)	(10.59)	(8.07)	(10.07)	(8.13)
Transportation costs	(0.41)	(0.36)	(0.47)	(0.36)	(0.42)
Amortization of injectants	(1.25)	(1.10)	(0.94)	(1.13)	(1.00)
Operating netback	$ 38.81	$ 33.94	$ 24.31	$ 32.54	$ 24.51

	Three months ended			Twelve months ended	
Light Crude Netbacks ($ per bbl)	**Dec 31, 2005**	**Sept 30, 2005**	**Dec 31, 2004**	**Dec 31, 2005**	**Dec 31, 2004**
Sales price	$ 59.40	$ 63.95	$ 44.76	$ 58.59	$ 43.21
Other production income	0.17	0.37	0.48	0.37	0.45
	59.57	64.32	45.24	58.96	43.66
Processing, interest and other income	0.34	0.64	0.51	0.47	0.46
Royalties	(6.47)	(11.03)	(9.65)	(8.64)	(7.62)
Operating costs	(14.32)	(12.85)	(9.17)	(12.28)	(9.31)
Transportation costs	(0.27)	(0.29)	(0.23)	(0.29)	(0.23)
Amortization of injectants	(3.63)	(3.14)	(2.67)	(3.21)	(2.58)

Operating netback	$ 35.22	$ 37.65	$ 24.03	$ 35.01	$ 24.38

	Three months ended			Twelve months ended	
Heavy Oil Netbacks ($ per bbl)	**Dec 31, 2005**	**Sept 30, 2005**	**Dec 31, 2004**	**Dec 31, 2005**	**Dec 31, 2004**
Sales price	$ 31.77	$ 47.74	$ 26.99	$ 33.32	$ 32.45
Processing, interest and other income	0.74	(0.83)		0.36	
Royalties	(2.98)	(8.00)	(4.19)	(4.53)	(4.87)
Operating costs	(11.60)	(16.30)	(9.44)	(15.65)	(9.85)
Operating netback	$ 17.93	$ 22.61	$ 13.36	$ 13.50	$ 17.73

Natural Gas Netbacks ($ per mcf)	**Three months ended**			**Twelve months ended**	
	Dec 31, 2005	**Sept 30, 2005**	**Dec 31, 2004**	**Dec 31, 2005**	**Dec 31, 2004**
Sales price	$11.97	$ 8.57	$ 7.02	$ 8.76	$ 6.80
Processing, interest and other income	0.19	0.09	0.24	0.23	0.20
Royalties	(2.62)	(1.47)	(1.34)	(1.70)	(1.26)
Operating costs	(1.38)	(1.31)	(1.16)	(1.24)	(1.15)
Transportation costs	(0.12)	(0.09)	(0.14)	(0.10)	(0.12)
Operating netback	$ 8.04	$ 5.79	$ 4.62	$ 5.95	$ 4.47

NGL Netbacks ($ per bbl)	**Three months ended**			**Twelve months ended**	
	Dec 31, 2005	**Sept 30, 2005**	**Dec 31, 2004**	**Dec 31, 2005**	**Dec 31, 2004**
Sales price	$ 58.46	$ 57.75	$ 48.04	$ 54.22	$ 42.21
Royalties	(21.29)	(20.57)	(19.37)	(17.66)	(15.43)
Operating costs	(10.05)	(10.13)	(7.87)	(9.04)	(7.94)
Transportation costs			(0.10)		(0.10)
Operating netback	$ 27.12	$ 27.05	$ 20.70	$ 27.52	$ 18.74

Interest

Interest expense decreased by 28 percent to $21.6 million in 2005 from $29.9 million in 2004, reflecting a lower average debt level, the impact of the appreciation of the Canadian dollar on U.S. dollar denominated interest and lower standby fees. Standby fees in 2004 of $3.9 million were related to the set-up of bridge financing utilized for the 2004 Murphy acquisition. Imputed interest on the note payable to Emera Offshore Incorporated (Emera) was also recorded in the amount of $1.3 million (2004 $1.6 million).

The average interest rate on Pengrowth s long term debt outstanding at December 31, 2005 is 5.1 percent. Approximately 63 percent of Pengrowth s outstanding debt as at December 31, 2005 incurs interest expense payable in U.S. dollars and therefore remains subject to fluctuations in the U.S. dollar exchange rate. The note payable is non-interest bearing.

General and Administrative

($ million)	Three months ended			Twelve months ended	
	Dec 31, 2005	Sept 30, 2005	Dec 31, 2004	**Dec 31, 2005**	Dec 31, 2004
Cash G&A expense	**7.7**	7.0	6.5	**27.4**	22.1
$ per boe	**1.36**	1.29	1.23	**1.27**	1.12
Non-cash G&A expense	**0.8**	0.6	0.4	**2.9**	2.3
$ per boe	**0.14**	0.11	0.08	**0.13**	0.12

Total G&A ($ million)	**8.5**	7.6	6.9	**30.3**	24.4
Total G&A ($ per boe)	**1.50**	1.40	1.31	**1.40**	1.24

The cash component of General and Administrative (G&A) increased due to a number of factors including the addition of personnel and office space in conjunction with the Murphy acquisition as well as a general increase in financial reporting, legal and regulatory costs related to the growth in our unitholder base and increasing regulatory requirements including preparing for compliance with the Sarbanes-Oxley Act and the related requirement to report on internal controls. The non-cash compensation is expense related to the value of trust unit options and rights (see Note 2 and Note 10 to the financial statements for details). Also included in 2005 G&A is $0.9 million (2004 $0.8 million) for estimated reimbursement of G&A expenses incurred by the Manager, pursuant to the management agreement.

Management Fees

($ million)	**Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	**Dec 31, 2005**	Dec 31, 2004
	Three months ended			Twelve months ended	
Management Fee	**2.2**	1.6	1.4	**9.1**	6.8
Performance Fee	**2.2**	1.9	1.2	**6.9**	6.1
Total ($ million)	**4.4**	**3.5**	2.6	**16.0**	12.9
Total ($ per boe)	**0.77**	0.65	0.48	**0.74**	0.66

Under the current management agreement, which came into effect July 1, 2003 for two three-year terms ending June 30, 2009, the Manager will earn a performance fee if the Trust s total returns exceed eight percent per annum on a three year rolling average basis. At the end of the first term, a review process will determine whether to extend the agreement for the second term. The maximum fees payable, including the performance fee, is limited to 80 percent of the fees that would otherwise have been payable under the previous management agreement for the first three years and 60 percent for the subsequent three years.

The Trust achieved a three-year average total return of 36 percent per annum at the end of 2005; as a result the Manager earned the maximum fee payable under the new management agreement.

Foreign Currency Gains and Losses

Pengrowth recorded a net foreign exchange gain of $7.0 million in 2005, compared to a foreign exchange gain of $17.3 million in 2004. Included in the 2005 gain is a $7.8 million unrealized foreign exchange gain related to the U.S. dollar denominated debt. This gain arises as a result of the increase in the Canadian to U.S. dollar exchange rate in 2005 from a rate of approximately $0.83 at December 31, 2004 to a rate of approximately $0.86 at December 31, 2005. Offsetting this gain is a realized foreign exchange loss of $0.8 million related mainly to U.S. dollar denominated receivables. Revenues are recorded at the average exchange rate for the production month in which they accrue, with payment being received on or about the 25th of the following month. As a result of the increase in the Canadian dollar relative to the U.S. dollar over the course of the year, a foreign exchange loss was recorded to the extent that there was a difference between the average exchange rate for the month of production and the exchange rate at the date the payments were received on that portion of production sales that are received in U.S. dollars. Pengrowth has arranged a significant portion of its long term debt in U.S. dollars as a natural hedge against a stronger Canadian dollar, as the negative impact on oil and gas sales is somewhat offset by a reduction in the U.S. dollar denominated interest cost (See Note 12 to the financial statements for further detail).

Depletion, Depreciation and Accretion

($ million)	**Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	**Dec 31, 2005**	Dec 31, 2004
	Three months ended			Twelve months ended	
Depletion and Depreciation	**71.4**	73.5	69.4	**285.0**	247.3
$ per boe	**12.63**	13.57	13.14	**13.15**	12.58
Accretion	**3.6**	3.6	3.2	**14.2**	10.6
$ per boe	**0.64**	0.66	0.60	**0.65**	0.54

Depletion and depreciation of property, plant and equipment and other assets is provided on the unit of production method based on total proved reserves. The provision for depletion and depreciation increased 15 percent in 2005 due to a larger depletable asset base and a higher depletion rate (production as a percentage of total proved reserves).

Accretion increased 34 percent year-over-year due to a larger Asset Retirement Obligation (ARO).

Taxes

In determining its taxable income, the Corporation deducts payments made to the Trust, effectively transferring the income tax liability to unitholders thus reducing taxable income to nil. Under the Corporation s current distribution policy, funds are withheld from distributable cash to fund future capital expenditures and repay debt. As a result of increased amounts being withheld to fund capital spending, the Corporation could become subject to taxation on a portion of its income in the future. This can be mitigated through various options including the issuance of additional trust units, increased tax pools from additional capital spending, modifications to the distribution policy or changes to the corporate structure. As a result, the Corporation does not anticipate the payment of any cash income taxes in the foreseeable future.

Capital taxes paid or payable by the Corporation, based on debt and equity levels at the end of the year, amounted to $6.2 million in 2005 (2004 $4.6 million). This amount is comprised of Federal Large Corporations Tax of $2.2 million (2004 $1.3 million) and Saskatchewan Capital Tax and Resource Surcharge of $4.0 million (2004 $3.2 million). The increase in 2005 capital taxes is due to a higher taxable capital base from the Crispin acquisition and increased capital expenditures relative to 2004.

The corporate acquisition of Crispin in 2005 resulted in Pengrowth recording an additional future tax liability of $22.2 million. A $75.6 million future tax liability was initially recorded in 2004 as a result of the Murphy acquisition. The future tax liability represents the difference between the tax basis and the fair values assigned to the acquired assets. A comparison of the fair value and tax basis at the end of the year increased the future tax liability by $12.3 million to $110.1 million.

Capital Expenditures

During 2005, Pengrowth spent $175.7 million on development and optimization activities. The largest expenditures were in Judy Creek ($36.7 million), SOEP ($27.2 million), Princess ($11.1 million), Weyburn ($8.8 million), Prespatou ($7.5 million) and Swan Hills ($7.2 million). Pengrowth does not typically participate in high risk exploration activities and in 2005 most of the capital spent on development was directed towards increasing production, arresting production declines and improving recovery through infill drilling.

	Three months ended			Twelve months ended	
($ million)	**Dec 31, 2005**	Sept 30, 2005	Dec 31, 2004	**Dec 31, 2005**	Dec 31, 2004
Geological and geophysical	**0.7**	0.2	0.2	**2.1**	0.6
Drilling and completions	**40.4**	29.8	36.1	**129.6**	111.3
Plant and facilities	**10.2**	10.0	17.7	**34.1**	49.1
Land purchases	**8.8**	0.8	0.2	**9.9**	2.3
Development capital	**60.1**	40.8	54.2	**175.7**	163.3
Acquisitions				**175.1**	569.7
Total capital expenditures and acqusit	**60.1**	40.8	54.2	**350.8**	733.0

Pengrowth s planned capital expenditures for maintenance and development opportunities at existing properties are approximately $236 million for 2006 which is the largest capital program in Pengrowth s history. Approximately half of the 2006 spending will be on a 280 gross well (132 net well) drilling program. The remainder of the budget will be spent on recompletions and reactivations, development of coalbed methane resources, production enhancements and ongoing maintenance. Pengrowth s 2006 capital program targets the furtherance of Pengrowth s short, medium and long term objectives, reflecting Pengrowth s focus on pursuing a balanced approach to the development of its key assets. While the most significant portion of Pengrowth s 2006 capital program will involve the continued development and maintenance of existing production and properties, a key element of the 2006 program will be further development of mid and longer term plays or projects in coalbed methane, heavy oil and enhanced oil recovery. Pengrowth anticipates funding its 2006 capital expenditures through a combination of undistributed cash from operations, unused credit facilities and any proceeds from property dispositions.

Acquisitions and Dispositions

On February 28, 2005, Pengrowth closed the acquisition of an additional 11.9 percent working interest in Swan Hills increasing Pengrowth s total working interest in the unit to 22.3 percent. The purchase price was $87 million, after adjustments from the October 1, 2004 effective date to the closing date.

On April 29, 2005, Pengrowth completed the acquisition of Crispin which held interests in oil and natural gas assets mainly in Alberta. This represented Pengrowth s first acquisition of a publicly traded corporation and was funded through the issuance of Class A and Class B trust units valued at approximately $88 million. Pengrowth also assumed debt of approximately $20 million as part of the acquisition.

During the second half of 2005, Pengrowth received approximately $38 million of proceeds from the sale of non-core oil and natural gas properties with associated production of approximately 600 boe per day.

On May 31, 2004, Pengrowth acquired oil and natural gas assets in Alberta and Saskatchewan from a subsidiary of Murphy Oil Corporation for a purchase price of $550 million prior to adjustments.

On August 12, 2004, Pengrowth acquired an additional 34.4 percent interest in Kaybob Notikewin Unit No. 1 for a purchase price of $20 million, bringing Pengrowth s total working interest in this unit to just below 99 percent.

Goodwill

In accordance with Canadian GAAP, Pengrowth recorded goodwill of $12.2 million upon the Crispin acquisition in 2005 and $170.6 million upon the Murphy acquisition in 2004. The goodwill value was determined based on the excess of total consideration paid less the net value assigned to other identifiable assets and liabilities, including the future income tax liability. Details of the acquisitions are provided in Note 4 to the financial statements.

Working Capital

Working capital declined by $33.7 million from a working capital deficiency of $78.5 million in 2004 to a working capital deficiency of $112.2 million as at December 31, 2005. Most of the working capital decline is attributable to an increase in bank indebtedness, accounts payable and accrued liabilities, distributions payable to unitholders and the current portion of the note payable, offset by an increase in accounts receivable as at December 31, 2005.

Pengrowth frequently operates with a working capital deficiency as a result of the fact that distributions related to two production months of operating income are payable to unitholders at the end of any month, but only one month of production is still receivable. At the end of December, distributions related to November and December production months were payable on January 15 and February 15 respectively. November s production revenue, received on December 25, is temporarily applied against Pengrowth s revolving credit facility until the distribution payment on January 15.

Financial Resources and Liquidity

At year-end 2005, Pengrowth had a long term debt to debt-plus-equity at book value ratio of 0.2 and maintained $370 million in committed credit facilities which were reduced by drawings of $35 million and by $17 million in letters of credit outstanding at year-end. In addition, Pengrowth maintains a $35 million demand operating line of credit. Pengrowth remains well positioned to fund its 2006 development program and to take advantage of acquisition opportunities as they arise. At December 31, 2005, Pengrowth had $337 million available to draw from its credit facilities.

Long term debt at December 31, 2005 included fixed rate term debt denominated in U.S. dollars which translated to Cdn $232.6 million. Due to the appreciation of the Canadian dollar relative to the U.S. dollar, an unrealized gain of Cdn $57.6 million has been recorded since the U.S. dollar denominated debt was issued in April of 2003. Long term debt at December 31, 2005 also included fixed rate term debt denominated in U.K. £50 million which translated to Cdn $100.5 million.

Through a series of hedging transactions, Pengrowth fixed the exchange rate in Canadian dollars for all future interest payments and repayment at maturity.

Pengrowth s long term debt increased by $22.7 million in fiscal 2005 to $368.1 million at December 31, 2005. At the end of 2005 Pengrowth also had a $20 million non-interest bearing note payable to Emera related to the purchase of the SOEP offshore facilities from Emera on December 31, 2003. The terms of this note are provided in Note 7 to the financial statements.

During the year Pengrowth incurred $87 million of new debt to fund the acquisition of an additional interest in Swan Hills and assumed $20 million of bank debt from the acquisition of Crispin. Pengrowth was able to fund this new debt from its existing credit facilities.

Financial Leverage and Coverage

	Twelve months ended	
	Dec 31, 2005	Dec 31, 2004
Distributable cash to interest expense (times)	**29**	13
Long term debt to distributable cash (times)	**0.6**	0.9
Long term debt to debt plus book equity (%)	**20**	19

Commitments and Contractual Obligations

($ thousands)	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
Long term debt (1)					174,450	193,639	368,089
Interest payments on long term debt (2)	17,298	17,298	17,298	17,298	11,564	34,546	115,302
Note payable	20,000						20,000
Operating leases							
Office rent	2,030	2,070	3,096	3,055	3,036	21,529	34,816
Vehicle leases	852	776	604	306	91		2,629
	2,882	2,846	3,700	3,361	3,127	21,529	37,445
Purchase obligations							
Pipeline transportation	43,839	38,197	34,981	29,813	11,748	53,525	212,103
Capital expenditures	33,323	7,098	294				40,715
CO_2 purchases	5,119	4,357	4,198	4,232	4,267	18,728	40,901
	82,281	49,652	39,473	34,045	16,015	72,253	293,719
Remediation trust fund payments	250	250	250	250	250	11,250	12,500

	122,711	**70,046**	**60,721**	**54,954**	**205,406**	**333,217**	**847,055**

(1) Foreign dollar denominated debt due as follows U.S. $150 million, in April 2010, U.S. $50 million, in April 2013 and £50 million in December 2015, translated at the Dec 31, 2005 exchange rate.

(2) Interest payments on foreign denominated debt, calculated based on Dec 31, 2005 foreign exchange rate.

Related Party Transactions

Details of related party transactions incurred in 2005 and 2004 are provided in Note 15 to the financial statements. These transactions include the management fees paid to the Manager. The Manager is controlled by James S. Kinnear, the Chairman, President and Chief Executive Officer of the Corporation. The management fees paid to the Manager are pursuant to a management agreement which has been approved by the trust unitholders. Mr. Kinnear does not receive any salary or bonus in his capacity as a director and officer of the Corporation and has not received any new trust unit options or rights since November 2002.

Related party transactions in 2005 also include $0.7 million (2004 $0.8 million) paid to a law firm controlled by the Vice President and Corporate Secretary of Pengrowth Corporation, Charles V. Selby. These fees are paid in respect of legal and advisory services provided by the Vice President and Corporate Secretary. Mr. Selby does not receive any salary or bonus in his capacity as Vice President and Corporate Secretary of the Corporation. Mr. Selby has from time to time been granted trust unit rights and options.

Ceiling Test

Under Canadian GAAP, a ceiling test is applied to the carrying value of the property, plant and equipment and other assets. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. There was a significant surplus in the ceiling test at year-end 2005.

Asset Retirement Obligations

The total future ARO were estimated by management based on estimated costs to remediate, reclaim and abandon wells and facilities based on Pengrowth s working interest and the estimated timing of the costs to be incurred in future periods. Pengrowth has estimated the net present value of its total ARO to be $185 million as at December 31, 2005 (2004 $172 million), based on a total escalated future liability of $1,041 million (2004 $551 million). The significant change in the estimated future liability is due to increasing regulatory requirements, changing the assumptions of economic life to agree with GLJ Petroleum Consultants Ltd. (GLJ) economic life and increasing the future inflation rate. These costs are expected to be incurred over 50 years with the majority of the costs incurred between 2032 and 2054. Pengrowth s credit adjusted risk free rate of eight percent (2004 eight percent) and an inflation rate of 2.0 percent (2004 1.5 percent) were used to calculate the net present value of the ARO.

Remediation Trust Funds & Remediation and Abandonment Expenses

During 2005, Pengrowth contributed $1.3 million into trust funds established to fund certain abandonment and reclamation costs associated with Judy Creek and SOEP. The balance in these remediation trust funds was $8.3 million at December 31, 2005.

Pengrowth takes a proactive approach to managing its well abandonment and site restoration obligations. There is an on-going program to abandon wells and reclaim well and facility sites. In 2005, Pengrowth spent $7.4 million on abandonment and reclamation (2004 $4.4 million). Pengrowth expects to spend approximately $11 million per year, prior to inflation, over the next ten years on remediation and abandonment.

Distributable Cash, Distributions and Taxability of Distributions

Pengrowth generated $619.7 million ($3.94 per average trust unit outstanding) of distributable cash from 2005 operations, compared to $401.2 million ($3.01 per unit) in 2004. Distributions paid or declared were $446.0 million for 2005 (2004 $363.1 million) and as a percentage of cash generated from operations (payout ratio) represent approximately 72 percent (2004 90 percent).

The Board of Directors may change the amount withheld in the future, depending on a number of factors, including future commodity prices, capital expenditure requirements, and the availability of debt and equity capital. Pursuant to the Royalty Indenture, the Board of Directors can establish a reserve for certain items including up to 20 percent of Gross Revenue to fund future capital expenditures or for the payment of royalty income in any future period.

The following discussion relates to the taxation of Canadian unitholders only. For detailed tax information relating to non-residents, please refer to our website www.pengrowth.com. Cash distributions are comprised of a return of capital portion, which is tax deferred, and return on capital portion which is taxable income. The return of capital portion reduces the cost base of a unitholders trust units for purposes of calculating a capital gain or loss upon ultimate disposition.

Cash distributions are paid to unitholders on the 15th day of the second month following the month of production. Cash distributions paid in the 2005 calendar year totaled $2.78 per trust unit and are 80 percent return on capital (taxable) or $2.22 per trust unit and 20 percent return of capital (tax deferred) or $0.56 per trust unit. Changes in the estimated taxable and deferred portion of the cash distributions are announced quarterly.

2005 Distribution Taxability Information

Payment Date	Taxable Amount (Other Income)	Tax deferred Amount (Return of Capital)	Total Distribution
January 15, 2005	$ 0.1840	$ 0.0460	$0.2300
February 15, 2005	$ 0.1840	$ 0.0460	$0.2300
March 15, 2005	$ 0.1840	$ 0.0460	$0.2300
April 15, 2005	$ 0.1840	$ 0.0460	$0.2300
May 15, 2005	$ 0.1840	$ 0.0460	$0.2300
June 15, 2005	$ 0.1840	$ 0.0460	$0.2300
July 15, 2005	$ 0.1840	$ 0.0460	$0.2300
August 15, 2005	$ 0.1840	$ 0.0460	$0.2300
September 15, 2005	$ 0.1840	$ 0.0460	$0.2300
October 15, 2005	$ 0.1840	$ 0.0460	$0.2300
November 15, 2005	$ 0.1840	$ 0.0460	$0.2300
December 15, 2005	$ 0.2000	$ 0.0500	$0.2500
	$ 2.2240	$ 0.5560	$2.7800

There is no standardized measure of distributable cash and therefore distributable cash, as reported by Pengrowth, may not be comparable to similar measures presented by other trusts. In conjunction with the change to Pengrowth s withholding practice, distributable cash as presented below may not be comparable to previous disclosures. The following table provides a reconciliation of distributable cash.

($ thousands, except per unit amounts)	Three months ended			Twelve months ended	
	Dec 31, 2005	Sept 30, 2005	Dec 31, 2004	**Dec 31, 2005**	Dec 31, 2004
Cash generated from operations	196,588	158,976	93,287	618,070	404,167
Change in non-cash operating working capital	(7,993)	(789)	8,576	(9,833)	(1,173)
Change in deferred injectants	7,411	892	3,228	10,265	746
Change in remediation trust funds	784	(272)	32	(20)	(917)
Change in deferred charges	(793)	2,818	(473)	1,235	(1,893)
Other	(118)	384	308	22	248
Distributable cash	195,879	162,009	104,958	619,739	401,178

Allocation of Distributable cash

Cash withheld	76,021	52,156	8,492	173,762	38,117
Distributions paid or declared	119,858	109,853	96,466	445,977	363,061
Distributable cash	195,879	162,009	104,958	619,739	401,178
Distributable cash per unit	1.23	1.02	0.77	3.94	3.01
Distributions paid or declared per unit	0.75	0.69	0.69	2.82	2.63
Payout ratio	61%	69%	103%	72%	90%

At this time, Pengrowth anticipates that approximately 75 to 80 percent of 2006 distributions will be taxable to Canadian residents; this estimate is subject to change depending on a number of factors including, but not limited to, the level of commodity prices, acquisitions, dispositions, and new equity offerings.

Trust Unit Information

Pengrowth had 159,864,083 trust units outstanding at December 31, 2005, compared to 152,972,555 trust units at December 31, 2004. The weighted average number of trust units during the year was 157,127,181 (2004 133,935,485).

On April 29, 2005, Pengrowth issued 4.2 million trust units to complete the Crispin acquisition (see Note 4 to the financial statements for further detail).

Class A and Class B Trust Unit Structure

Maintaining its status as a mutual fund trust under *Income Tax Act* (Canada) is of fundamental importance to the Trust. Generally speaking, in addition to several other requirements, in order for a trust such as Pengrowth to be a mutual fund trust under the *Income Tax Act* it must satisfy one of two tests. The first test is a benefit test that requires that the trust must not be established or maintained primarily for the benefit of non-residents of Canada (which is generally interpreted to mean that the majority of unitholders must be residents of Canada) (the Benefit Test). The second test is a property test that requires that, at all times after February 21, 1990, all or substantially all of the trust s property consist of property other than taxable Canadian property (the Property Exception). Pengrowth is aware that many other oil and gas income trusts have significantly greater than 50 percent non-resident ownership and are relying on the Property Exception to maintain their mutual fund trust status.

For reasons that may be unique to the Trust, it was not clear that the Trust could rely upon the Property Exception, as a sale and leaseback transaction entered into with the Corporation in 1998 regarding certain facilities at Judy Creek may have resulted in the Trust s taxable Canadian property exceeding the threshold required by the Property Exception. On November 26, 2004, the Trust received a customary form of comfort letter from the Department of Finance (Canada) stating that the Department of Finance will recommend to the Minister of Finance that an amendment be made to the Property Exception that would clarify the Trust s ability to rely upon the Property Exception.

As a result of this uncertainty, the Trust adopted the Class A and Class B trust unit structure, which requires that the Class A trust units constitute not more than 49.75 percent of the outstanding trust units of the Trust and that all of the Class B trust units be held by residents of Canada, to ensure that the Trust would satisfy the Benefit Test. The Trust received an advance tax ruling from the Canada Revenue Agency on July 26, 2004 and an amended ruling on December 1, 2004 that confirmed that the Trust would continue to be a mutual fund trust if the Class A trust units constituted less than the ownership threshold of 49.75 percent by June 1, 2005 and the Trust was a mutual fund trust prior to that date.

As at December 31, 2004, the Class A trust units represented 50.2 percent of the outstanding trust units of the Trust. As a result of a public offering of Class B trust units in December of 2004, the issuance of a majority of Class B trust units in connection with Pengrowth s acquisition of Crispin in 2005 and the issuance of Class B trust units in accordance with the Distribution Reinvestment Program and other Pengrowth incentive plans, the ownership threshold of 49.75 percent for the Class A trust units was achieved prior to June 1, 2005 in accordance with the advance income tax ruling. On December 6, 2004, the Minister of Finance indicated that further discussions and consultations concerning the appropriate tax treatment of non-residents owning resource properties through mutual fund trusts would take place.

At present, Pengrowth is maintaining the Class A and Class B trust unit structure in compliance with the advance income tax ruling. The Board of Directors considers it prudent at this time to continue the Class A and Class B trust unit structure.

The Board of Directors may determine, based upon market circumstances as they exist at that time or other factors, that it is in the best interests of all unitholders to: (a) remove the requirement to comply with the ownership threshold that restricts the Class A trust units to 49.75 percent of the outstanding trust units; (b) remove the residency restrictions pertaining to the holding of Class B trust units; (c) permit a free conversion of Class B trust units to Class A trust units; (d) permit the consolidation of the trust unit capital of the Trust; (e) allow a controlled conversion of Class B trust units to Class A trust units over time to preserve an orderly market; (f) maintain the Class A and Class B trust unit structure until market circumstances become more favorable to both classes of unitholders; or (g) take such other action as the Board of Directors may consider appropriate.

Subsequent Event

On January 12, 2006, Pengrowth announced certain transactions with Monterey under which Pengrowth has sold oil and gas properties for $22 million of cash and eight million shares in Monterey. As at February 27, 2006 Pengrowth holds approximately 34 per percent of the common shares of Monterey.

Outlook

Pengrowth will seek to provide attractive long term returns for unitholders. Our business objectives include:

- Operating our properties in a safe and prudent manner in order to protect our employees, the public, the environment and our investment;
- Maintaining a balanced portfolio of oil and gas properties in our key focus areas;
- Growing production and reserves through accretive acquisitions and low risk development drilling;
- Increasing our undeveloped land position;
- Continuing to optimize costs and maximize netbacks;
- The selective disposition of oil and gas properties that do not meet our return objectives;
- Continuing to maintain a stable distribution policy while withholding a portion of distributable cash to fund future capital programs.

At this time, Pengrowth is forecasting average 2006 production of 54,000 to 56,000 boe per day from our existing properties. This estimate incorporates anticipated production additions from our 2006 development program, offset by the impact of divestitures of approximately 1,300 boe per day and expected production declines from normal operations. The above estimate excludes the potential impact of any future acquisitions or divestitures.

Total operating costs for 2006 are expected to increase to approximately $220 million. This increase is due to the addition of a full-year of operating expenses associated with Pengrowth s increased working interest in Swan Hills and the acquisition of Crispin. Assuming Pengrowth s average production for 2006 as forecast above, Pengrowth currently estimates 2006 per boe operating costs of approximately $11.00 per boe.

Budgeted capital expenditures for 2006 total approximately $236 million. Approximately half of the budgeted 2006 expenditures is for a 280 gross wells (132 net wells) drilling program, 27 percent are for facilities and maintenance, nine percent are for land and seismic acquisitions, and eight percent for recompletions, workovers, CO_2 pilot and other. Pengrowth s 2006 capital program targets the furtherance of Pengrowth s short, medium and long term objectives, reflecting Pengrowth s focus on pursuing a balanced approach to the development of its key assets. While the most significant portion of Pengrowth s 2006 capital program will involve the continued development and maintenance of existing production and properties, a key element of the 2006 program will be further development of mid and longer term plays or projects in coalbed methane, heavy oil and enhanced oil recovery. Pengrowth anticipates funding its 2006 capital expenditures through a combination of undistributed cash from operations, unused credit facilities and any proceeds from property dispositions.

CONFERENCE CALL

Pengrowth will hold a conference call beginning at 11:00 A.M. Eastern Time (9:00 A.M. Mountain Time) on Tuesday, February 28, 2006 during which Management will review Pengrowth s 2005 fourth quarter and full year financial and operating results and respond to inquiries from the investment community. To participate callers may dial (866) 540-8136 or Toronto local (416) 340-8010. To ensure timely participation in the teleconference callers are encouraged to dial in 10-15 minutes prior to commencement of the call to register. A live audio webcast will be accessible through the Webcast and Multimedia Centre section of Pengrowth s website at www.pengrowth.com. The webcast will be archived through February 28, 2007. A telephone replay will be available thru to midnight Eastern Time on Tuesday, March 7, 2006 by dialing (800) 408-3053 or Toronto local (416) 695-5800 and entering passcode number 3176117 followed by the pound key.

PENGROWTH CORPORATION
James S. Kinnear, President

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SUPPLEMENTAL INFORMATION

Reserves

Based on an independent engineering evaluation conducted by GLJ effective December 31, 2005 and prepared in accordance with NI 51-101, Pengrowth had proved plus probable reserves of 219.4 mmboe. This represents 100 percent replacement of proved plus probable reserves through the acquisition of 16.7 mmboe and additions of 8.6 mmboe resulting from drilling activity, improved recoveries and technical revisions. Additions were offset by 21.7 mmboe of production and dispositions amounting to 2.8 mmboe.

Proved producing reserves are estimated at 143.7 mmboe; these reserves represent 82 percent of the total proved reserves of 175.6 mmboe and 66 percent of proved plus probable reserves. The total proved reserves account for 80 percent of proved plus probable reserves. These percentages are virtually unchanged from 2004.

Using a ten percent discount factor and GLJ January 1, 2006 pricing, the proved producing reserves account for 75 percent of the proved plus probable value while the total proved reserves account for 85 percent of the proved plus probable value. Using a 6:1 boe conversion rate for natural gas, approximately 45 percent of Pengrowth s reserves are light/medium crude oil, 39 percent are natural gas, 9 percent are NGLs and 7 percent are heavy oil.

Pengrowth is a geographically diversified energy trust with properties located across Canada in the provinces of British Columbia, Alberta, Saskatchewan and offshore Nova Scotia. On a proved plus probable reserve basis, the Alberta, Saskatchewan, British Columbia and offshore Nova Scotia holdings account for 71 percent, 14 percent, 10 percent, and 5 percent, respectively of reserves reported by GLJ.

Reserves Summary 2005

Company Interest (Company Gross Interest* plus Royalty Interest Reserves)

	Light and Medium Crude Oil mbbl	Heavy Oil mbbl	NGLs mbbl	Natural Gas bcf	Oil Equivalent 2005 mboe	Oil Equivalent 2004 mboe
Proved Producing	58,219	10,924	13,566	366.2	143,741	142,353
Proved Developed Non Producing	365	62	637	24.3	5,113	4,825
Proved Undeveloped	18,768	1,699	1,139	30.8	26,745	28,324
Total Proved	77,351	12,684	15,342	421.3	175,599	175,502
Proved plus Probable	98,684	15,790	18,985	515.6	219,396	218,613

Net Interest (Company Net Interest* which is the Company Interest Reserves less Royalties Payable)

	Light and Medium Crude Oil mbbl	Heavy Oil mbbl	NGLs mbbl	Natural Gas bcf	Oil Equivalent 2005 mboe	Oil Equivalent 2004 mboe
Proved Producing	49,693	9,621	9,334	289.4	116,877	116,798
Proved Developed Non Producing	308	57	460	18.4	3,893	3,757

Proved Undeveloped	15,991	1,420	805	23.9	22,200	23,616
Total Proved	65,992	11,098	10,600	331.7	142,970	144,171
Proved plus Probable	83,929	13,714	13,218	404.3	178,246	179,298

(*) means Company Gross Interest and Company Net Interest as defined in the Canadian Oil and Gas Evaluation Handbook (COGEH), Volume 2, Section 5.2, November 1,2005.

Reserve Reconciliation

Pengrowth added 25.3 mmboe of proved plus probable reserves during 2005, replacing production by 117 percent. The acquisition of Crispin and additional interest in Swan Hills accounted for approximately 66 percent of the reserve additions. The balance of additions resulted mainly from drilling and improved recovery. Most significant were drilling extensions at West Pembina, infill drilling and increased CO_2 miscible flood recovery in the Weyburn Unit. Disposition of various non-core assets resulted in a decrease of 2.8 mmboe.

Reserves Reconciliation 2005

Company Interest Volumes (before deduction of Royalty Burdens Payable)

	Light and Medium Crude Oil mbbl	Heavy Oil mbbl	NGLs mbbl	Natural Gas bcf	Oil Equivalent mboe
Total Proved					
December 31, 2004	74,175	14,622	15,488	427.3	175,502
Exploration & Development	0	81	715	19.8	4,096
Improved Recovery	2,328	134	448	1.7	3,193
Revisions	709	(101)	642	16.9	4,072
Acquisitions	9,106	0	376	19.3	12,699
Dispositions	(1,376)	0	(103)	(4.9)	(2,296)
Production	(7,591)	(2,052)	(2,224)	(58.8)	(21,667)
December 31, 2005	77,351	12,684	15,342	421.3	175,599
Proved plus Probable					
December 31, 2004	94,066	18,245	19,395	521.4	218,613
Exploration & Development	0	92	823	23.9	4,898
Improved Recovery	2,599	149	277	1.9	3,342
Revisions	(435)	(644)	343	6.5	344
Acquisitions	11,702	0	478	27.1	16,697
Dispositions	(1,657)	0	(107)	(6.4)	(2,831)
Production	(7,591)	(2,052)	(2,224)	(58.8)	(21,667)
December 31, 2005	98,684	15,790	18,985	515.6	219,396

Reserves Reconciliation 2005
Net After Royalty Volumes

	Light and Medium Crude Oil mbbl	Heavy Oil mbbl	NGLs mbbl	Natural Gas bcf	Oil Equivalent mboe
Total Proved					
December 31, 2004	63,572	12,733	10,974	341.4	144,171
Exploration & Development		71	494	15.6	3,163
Improved Recovery	1,986	117	309	1.3	2,635
Revisions	(354)	59	591	10.6	2,074
Acquisitions	7,769		260	15.2	10,561
Dispositions	(1,174)		(71)	(3.9)	(1,888)
Production	(5,807)	(1,882)	(1,957)	(48.6)	(17,746)
December 31, 2005	65,992	11,098	10,600	331.7	142,970
Proved plus Probable					
December 31, 2004	80,443	15,798	13,819	415.4	179,298
Exploration & Development		80	573	18.7	3,776
Improved Recovery	2,211	129	193	1.5	2,781
Revisions	(1,461)	(412)	332	1.0	(1,370)
Acquisitions	9,952		333	21.3	13,827
Dispositions	(1,409)		(75)	(5.0)	(2,320)
Production	(5,807)	(1,882)	(1,957)	(48.6)	(17,746)
December 31, 2005	83,929	13,714	13,218	404.3	178,246

Net Present Value (NPV) Summary 2005
At GLJ January 1, 2006 escalated prices and costs*

($ thousands)	Undiscounted	Discounted at 8%	Discounted at 10%	Discounted at 12%	Discounted at 15%
Proved Producing	3,676,741	2,563,707	2,401,037	2,262,789	2,089,851
Proved Developed Non Producing	148,744	94,965	87,578	81,363	73,662
Proved Undeveloped	559,904	269,672	229,572	196,476	156,685
Total Proved	4,385,388	2,928,344	2,718,187	2,540,628	2,320,198
Proved plus Probable	5,693,559	3,490,944	3,204,481	2,967,685	2,679,919

* Prior to provision for income taxes, interest, debt service charges and general and administrative expenses.
Constant Prices at December 31, 2005*

($ thousands)	Undiscounted	Discounted at 8%	Discounted at 10%	Discounted at 12%	Discounted at 15%
Proved Producing	4,745,097	3,127,174	2,895,985	2,701,198	2,460,128
Proved Developed Non Producing	183,180	115,627	105,969	97,813	87,701
Proved Undeveloped	770,444	396,166	342,540	297,883	243,694
Total Proved	5,698,721	3,638,966	3,344,494	3,096,895	2,791,524
Proved plus Probable	7,286,322	4,342,199	3,953,173	3,631,474	3,241,128

* Prior to provision for income taxes, interest, debt service charges and general and administrative expenses.

GLJ s January 1, 2006 price forecast is shown below:

Year	WTI Crude Oil (U.S.$/bbl)	Edmonton Light Crude Oil (Cdn$/bbl)	Natural Gas at AECO (Cdn$/mmbtu)
2006	57.00	66.25	10.60
2007	55.00	64.00	9.25
2008	51.00	59.25	8.00
2009	48.00	55.75	7.50
2010	46.50	54.00	7.20
2011	45.00	52.25	6.90
2012	45.00	52.25	6.90
2013	46.00	53.25	7.05
2014	46.75	54.25	7.20
2015	47.75	55.50	7.40
2016	48.75	56.50	7.55
Escalate thereafter	2.0% per year	2.0% per year	2.0% per year

Constant Prices at December 31, 2005

Year	WTI Crude Oil (U.S.$/bbl)	Edmonton Light Crude Oil (Cdn$/bbl)	Natural Gas at AECO (Cdn$/mmbtu)
2006	61.04	68.27	9.71

Net Asset Value at December 31, 2005

In the following table, Pengrowth s net asset value (NAV) is measured with reference to the present value of future net cash flows from reserves, as estimated by GLJ. The calculation is shown using both the GLJ escalated price forecast, and constant (year end 2005) prices.

($ thousands, except per unit amount)	GLJ 2006-01 Price Forecast	Constant Price Forecast
Value of Proved plus Probable Reserves discounted at 10%	3,204,481	3,953,173
Undeveloped lands (1)	145,344	145,344
Working Capital (2)	(28,222)	(28,222)
Remediation trust fund	8,329	8,329
Long term debt and Note Payable	(381,026)	(381,026)
Asset Retirement Obligation (3)	(110,243)	(118,243)
Net Asset Value	$2,838,663	$3,579,355
Units Outstanding (000 s)	159,864	159,864

Net Asset value per Unit	$ 17.76	$ 22.39

(1) Pengrowth s internal estimate

(2) Working capital excludes distributions payable

(3) The ARO is based on the same methodology used to calculate the ARO on Pengrowth s year end financial statements, except that the future expected ARO costs were inflated at 2 percent and discounted at 10 percent and well abandonment costs included in the GLJ report were deducted

Reserve Life Index

Pengrowth s proved reserve life index (RLI) remained the same at 8.6 years and the proved plus probable RLI of 10.5 years can be compared to last year s value of 10.4 years.

Reserve Life Index	2005	2004	2003
Total Proved	8.6	8.6	8.9
Proved plus Probable	10.5	10.4	10.6

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Finding and Development Costs

During 2005, Pengrowth spent $175.7 million on development and optimization activities, which added 11.4 mmboe of proved and 8.6 mmboe of proved plus probable reserves including revisions. The largest additions were from infill drilling and enhanced recovery development in the Weyburn Unit CO_2 miscible flood project and drilling extensions for gas in West Pembina.

In total, Pengrowth participated in drilling 286 gross wells (94 net wells) during 2005 with a 99 percent success rate. Pengrowth continues to develop shallow gas in southeast Alberta, drilling 44 infill wells at Princess and participating in 108 wells at Tilley. Pengrowth was also active in drilling for gas in northern Alberta, participating in 35 infill wells in the Dunvegan Gas Unit.

At Judy Creek, ongoing development of the hydrocarbon miscible flood project continue to be a focus for Pengrowth. Infill drilling and miscible flood pattern development and optimization contribute to arresting declines and improving recovery.

During 2005, significant capital expenditures were made at SOEP to further exploit gas reserves. Two successful wells, South Venture 3 and Venture 7, were drilled and brought on stream. The massive compression project at Thebaud is progressing with completion anticipated in late 2006 or early 2007.

In the southeast Saskatchewan Weyburn Unit, expansion and optimization of the partner operated CO_2 miscible flood enhanced oil recovery project progresses as planned. Forty-seven infill wells, both new and re-entry, were drilled and facilities are being expanded to accommodate higher CO_2 injection rates.

Acquisitions and Divestitures

During 2005 Pengrowth was again active in making strategic acquisitions. Pengrowth spent $175.1 million adding 10.4 mmboe of proved and 13.9 mmboe of proved plus probable reserves, net of some minor dispositions of scattered non-core properties.

In February 2005, Pengrowth acquired an additional 11.9 percent working interest in Swan Hills, increasing Pengrowth s total working interest in the unit to 22.3 percent. The purchase price was $87 million. The acquisition added 11.0 mmboe of proved plus probable reserves.

In April of 2005, Pengrowth completed the acquisition of Crispin adding approximately 1,900 boe per day of production and 5.2 mmboe of proved plus probable reserves. The acquisition was funded through the issuance of Class A and Class B trust units valued at approximately $88 million. Pengrowth also assumed debt of approximately $20 million as part of the acquisition.

In the latter half of 2005, Pengrowth concluded a disposition program selling non-core oil and natural gas properties with associated production of approximately 600 boe per day and 2.6 mmboe of proved plus probable reserves. Total disposition proceeds were $37.6 million.

Future Development Capital

If a company chooses to disclose finding and development costs, NI 51-101 requires that the calculation include changes in forecasted future development costs relating to the reserves. Future development costs reflect the amount of capital estimated by the independent evaluator that will be required to bring non-producing, undeveloped or probable reserves on stream. These forecasts of future development costs will change with time due to ongoing development activity, inflationary changes in capital costs and acquisition or disposition of assets. Pengrowth provides the calculation of finding and development costs both with and without change in future development costs.

FD&A Costs Company Interest Reserves

	Proved	Proved plus Probable
FD&A Costs Excluding Future Development Capital		
Exploration and Development Capital Expenditures ($000 s)	$175,700	$175,700
Exploration and Development Reserve Additions including Revisions (mboe)	11,361	8,591
Finding and Development Cost ($/boe)	$ 15.47	$ 20.45
Net Acquisition Capital ($000 s)	175,100	175,100
Net Acquisition Reserve Additions (mboe)	10,403	13,866
Net Acquisition Cost ($/boe)	16.83	12.63
Total Capital Expenditures including Net Acquisitions ($000 s)	350,800	350,800
Reserve Additions including Net Acquisitions (mboe)	21,764	22,457
Finding, Development and Acquisition Cost ($/boe)	16.12	15.62
FD&A Costs Including Future Development Capital		
Exploration and Development Capital Expenditures ($000 s)	175,700	175,700
Exploration and Development Change in FDC ($000 s)	(54,931)	(50,749)
Exploration and Development Capital including Change in FDC ($000 s)	120,769	124,951
Exploration and Development Reserve Additions including Revisions (mboe)	11,361	8,591
Finding and Development Cost ($/boe)	10.63	14.54
Net Acquisition Capital ($000 s)	175,100	175,100
Net Acquisition FDC ($000 s)	17,900	24,700
Net Acquisition Capital including FDC ($000 s)	193,000	199,800
Net Acquisition Reserve Additions (mboe)	10,403	13,866
Net Acquisition Cost ($/boe)	18.55	14.41
Total Capital Expenditures including Net Acquisitions ($000 s)	350,800	350,800
Total Change in FDC ($000 s)	(37,031)	(26,049)
Total Capital including Change in FDC ($000 s)	313,769	324,751
Reserve Additions including Net Acquisitions (mboe)	21,764	22,457
Finding, Development and Acquisition Cost including FDC ($/boe)	14.42	14.46

Total Future Net Revenue (Undiscounted)
GLJ January 1, 2006 escalated pricing:

($ thousands)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs*	Future Net Revenue Before Income Tax
Proved Producing	7,508,321	1,415,040	2,161,122	129,826	125,593	3,676,741
Proved Developed Nonproducing	253,600	56,850	38,331	7,933	1,743	148,744
Proved Undeveloped	1,540,086	240,315	535,055	197,668	7,145	559,904
Total Proved	9,302,007	1,712,204	2,734,507	335,427	134,481	4,385,388
Total Probable	2,516,295	473,676	655,671	66,363	12,413	1,308,171
Proved plus Probable	11,818,302	2,185,881	3,390,179	401,790	146,894	5,693,559

Constant Price at December 31, 2005:

($ thousands)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs*	Future Net Revenue Before Income Tax
Proved Producing	8,409,412	1,606,510	1,842,164	121,923	93,718	4,745,097
Proved Developed Nonproducing	293,753	67,811	33,775	7,642	1,345	183,180
Proved Undeveloped	1,749,618	314,087	471,885	188,804	4,398	770,444
Total Proved	10,452,783	1,988,409	2,347,823	318,370	99,460	5,698,721
Total Probable	2,628,744	534,619	443,673	60,868	1,983	1,587,601
Proved plus Probable	13,081,527	2,523,028	2,791,497	379,237	101,444	7,286,322

* Downhole abandonment costs

Business Risks

The amount of distributable cash available to unitholders and the value of Pengrowth Energy Trust units are subject to numerous risk factors. As the trust units allow investors to participate in the net cash flow from Pengrowth s portfolio of producing oil and natural gas properties, the principal risk factors that are associated with the oil and gas business include, but are not limited to, the following influences:

The prices of Pengrowth s products (crude oil, natural gas, and NGLs) fluctuate due to many factors including local and global market supply and demand, weather patterns, pipeline transportation, and political stability.

The marketability of our production depends in part upon the availability, proximity and capacity of gathering systems, pipelines and processing facilities. Operational or economic factors may result in the inability to deliver our products to market.

Geological and operational risks affect the quantity and quality of reserves and the costs of recovering those reserves. Our actual results will vary from our reserve estimates, and those variations could be material.

Government royalties, income taxes, commodity taxes, and other taxes, levies and fees have a significant economic impact on Pengrowth s financial results. Changes to federal and provincial legislation governing such royalties, taxes and fees could have a material impact on Pengrowth s financial results and the value of Pengrowth trust units.

Environmental laws and regulatory initiatives impact Pengrowth financially and operationally. We may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change.

Pengrowth s oil and gas reserves will be depleted over time and our level of distributable cash and the value of our trust units could be reduced if reserves and production are not replaced. The ability to replace production depends on Pengrowth s success in developing existing reserves, acquiring new reserves and financing this development and acquisition activity within the context of the capital markets.

Increased competition for properties will drive the cost of acquisition up and expected returns from the properties down.

A significant portion of our properties are operated by third parties. If these operators fail to perform their duties properly, or become insolvent, we may experience interruptions in production and revenues from these properties or incur additional liabilities and expenses as a result of the default of these third party operators.

Increased activity within the oil and gas sector can increase the cost of goods and services and make it more difficult to hire and retain professional staff.

Changing interest rates influence borrowing costs and the availability of capital.

- Investors interest in the oil and gas sector may change over time which would affect the availability of capital and the value of Pengrowth trust units.
- The value of Class A trust units and Class B trust units, relative to one another, may be influenced by the different markets in which the trust units trade, the restriction in entitlement of the Class B trust units to Canadian residents and the limitation in the number of Class A trust units beneath an ownership threshold of 49.75 percent of all trust units outstanding.
- Inflation may result in escalating costs which could impact unitholder distributions and the value of Pengrowth trust units.
- Canadian / U.S. exchange rates influence revenues and, to a lesser extent, operating and capital costs.
- The value of Pengrowth trust units is impacted directly by the related tax treatment of the trust units and the trust unit distributions, and indirectly by the tax treatment of alternative equity investments. Changes in Canadian or U.S. tax legislation could adversely affect the value of our trust units.

Pengrowth mitigates some of these risks by:

- Fixing the price on a portion of its future crude oil and natural gas production.
- Fixing the Canadian / U.S. exchange rate through financial hedging contracts or by fixing commodity prices in Canadian dollars.
- Offering competitive incentive-based compensation packages to attract and retain highly qualified and motivated professional staff.
- Adhering to strict investment criteria for acquisitions.
- Acquiring mature production with long life reserves and proven production.
- Performing extensive geological, geophysical, engineering and environmental analysis before committing to capital development projects.
- Geographically diversifying its portfolio.
- Controlling costs to maximize profitability.
- Developing and adhering to policies and practices that protect the environment and meet or exceed the regulations imposed by the government.
- Developing and adhering to safety policies and practices that meet or exceed regulatory standards.
- Ensuring strong third party operators for non-operated properties.
- Carrying insurance to cover physical losses and business interruption.

These factors should not be considered to be exhaustive. Additional risks are outlined in the Annual Information Form (AIF) of the Trust available on SEDAR at www.sedar.com on or before March 31, 2006.

Summary of Quarterly Results

The following table is a summary of quarterly results for 2005 and 2004. As this table illustrates, production and distributable cash were impacted positively by the Murphy acquisition in the second quarter of 2004.

This table also shows the relatively high commodity prices sustained throughout 2004 and 2005, which have had a positive impact on net income and distributable cash.

	2005			
	Q1	**Q2**	**Q3**	**Q4**
Oil and gas sales ($000 s)	**239,913**	**253,189**	**304,484**	**353,923**
Net income ($000 s)	**56,314**	**53,106**	**100,243**	**116,663**
Net income per unit ($)	**0.37**	**0.34**	**0.63**	**0.73**
Net income per unit diluted ($)	**0.37**	**0.34**	**0.63**	**0.73**
Distributable cash ($000 s)	**127,804**	**134,047**	**162,009**	**195,879**
Actual distributions paid or declared per unit ($)	**0.69**	**0.69**	**0.69**	**0.75**
Daily production (boe)	**59,082**	**57,988**	**58,894**	**61,442**
Total production (mboe)	**5,317**	**5,277**	**5,418**	**5,653**
Average realized price ($ per boe)	**44.97**	**47.79**	**56.07**	**62.55**
Operating netback ($ per boe)	**27.70**	**29.26**	**33.94**	**38.81**

	2004			
	Q1	Q2	Q3	Q4
Oil and gas sales ($000 s)	168,771	197,284	226,514	223,183
Net income ($000 s)	38,652	32,684	51,271	31,138
Net income per unit ($)	0.31	0.24	0.38	0.23
Net income per unit diluted ($)	0.31	0.24	0.38	0.23
Distributable cash ($000 s)	92,895	99,021	104,304	104,958
Actual distributions paid or declared per unit ($)	0.63	0.64	0.67	0.69
Daily production (boe)	45,668	51,451	60,151	57,425
Total production (mboe)	4,156	4,682	5,534	5,283
Average realized price ($ per boe)	40.37	41.83	40.90	42.08
Operating netback ($ per boe)	25.71	25.71	22.77	24.31

Selected Annual Information

Financial Results		Twelve months ended	
($ thousands)	Dec 31, 2005	Dec 31, 2004	Dec 31, 2003
Oil and gas sales*	1,151,510	815,751	702,732
Net income	326,326	153,745	189,297
Net income per unit	2.08	1.15	1.63
Distributable cash *	619,739	401,178	345,899

Actual distributions paid or declared per unit	2.82	2.63	2.68
Total assets	2,391,432	2,276,534	1,673,718
Long term financial liabilities**	381,026	383,616	294,300
Unitholders equity	1,475,996	1,462,211	1,159,433
Number of units outstanding at year-end (thousands)	159,864	152,973	123,874

* Prior years restated to conform to presentation adopted in the current year

** Long term debt plus long term portion of note payable and contract liabilities

Trust Unit Information

Trust Unit Trading after re-class*	High	Low	Close	Volume (000s)	Value ($ millions)
TSX PGF.A ($ Cdn)					
2005 1st quarter	28.29	22.15	24.03	2,049	53.3
2nd quarter	27.90	23.95	27.20	1,798	46.4
3rd quarter	30.10	26.30	29.50	2,047	58.0
4th quarter	29.80	23.64	27.41	1,324	35.2
Year	30.10	22.15	27.41	7,218	192.9
2004 1st quarter					
2nd quarter					
3rd quarter	24.19	19.10	22.67	1,672	35.5
4th quarter	26.33	20.03	24.93	2,607	58.9
Year	26.33	19.10	24.93	4,279	94.4
TSX PGF.B ($ Cdn)					
2005 1st quarter	19.90	16.10	17.05	29,219	543.7
2nd quarter	19.01	16.37	18.40	19,370	342.5
3rd quarter	21.26	18.25	20.58	22,738	441.0
4th quarter	23.38	17.27	22.65	19,747	411.0
Year	23.38	16.10	22.65	91,074	1,738.2
2004 1st quarter					
2nd quarter					
3rd quarter	20.00	18.03	18.87	5,588	105.6
4th quarter	20.04	17.51	18.50	16,007	301.8
Year	20.04	17.51	18.50	21,595	407.4
NYSE PGH ($ U.S.)					
2005 1st quarter	22.94	18.11	20.00	24,621	515.1
2nd quarter	22.74	19.05	22.25	16,153	335.0
3rd quarter	25.75	21.55	25.42	14,502	340.3
4th quarter	25.56	20.00	23.53	17,808	399.7
Year	25.75	18.11	23.53	73,084	1,590.1
2004 1st quarter					
2nd quarter					
3rd quarter	18.94	14.40	17.93	21,200	350.4
4th quarter	21.24	15.85	20.82	31,174	574.7
Year	21.24	14.40	20.82	52,374	925.1

Trust Unit Trading before re-class*	High	Low	Close	Volume (000s)	Value ($ millions)
TSX PGF.UN ($ Cdn)					
2004 1st quarter	21.25	15.55	17.98	30,620	567.8
2nd quarter	19.15	16.15	18.67	18,145	328.5
3rd quarter	19.75	18.52	19.42	3,554	68.5
4th quarter					
Year	21.25	15.55	19.42	52,319	964.8

NYSE PGH ($ U.S.)					
2004 1st quarter	16.60	12.10	13.70	36,899	525.6
2nd quarter	14.24	11.62	13.98	22,194	295.9
3rd quarter	14.95	13.84	14.64	5,797	84.5
4th quarter					
Year	14.95	11.62	14.64	64,890	906.0

** July 27, 2004, all trust units were re-classified into Class A or Class B units.

Class A Units trade on the NYSE under PGH and on the TSX under PGF.A.

Class B units trade only on the TSX under PGF.B.

* July 27, 2004, trust units were re-classified as Class A or Class B trust units. Class A trust units trade on the New York Stock Exchange (NYSE) under PGH and on the Toronto Stock Exchange (TSX) under PGF.A. Class B trust units trade only on the TSX under PGF.B.

PENGROWTH ENERGY TRUST

UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2005

PENGROWTH ENERGY TRUST
CONSOLIDATED BALANCE SHEETS
(Stated in thousands of dollars)

	As at December 31 2005 (unaudited)	As at December 31 2004 (audited)
ASSETS		
CURRENT ASSETS		
Accounts receivable	$ 127,394	$ 104,228
Inventory		439
	127,394	104,667
REMEDIATION TRUST FUNDS (Note 3)	8,329	8,309
DEFERRED CHARGES (Note 11)	4,886	3,651
GOODWILL (Note 4)	182,835	170,619
PROPERTY, PLANT AND EQUIPMENT AND OTHER ASSETS (Note 5)	2,067,988	1,989,288
	$ 2,391,432	$ 2,276,534
LIABILITIES AND UNITHOLDERS EQUITY		
CURRENT LIABILITIES		
Bank indebtedness	$ 14,567	$ 4,214
Accounts payable and accrued liabilities	111,493	80,423
Distributions payable to unitholders	79,983	70,456
Due to Pengrowth Management Limited	8,277	7,325
Note payable (Note 7)	20,000	15,000
Current portion of contract liabilities (Note 4)	5,279	5,795
	239,599	183,213
NOTE PAYABLE (Note 7)		20,000
CONTRACT LIABILITIES (Note 4)	12,937	18,216
LONG-TERM DEBT (Note 8)	368,089	345,400
ASSET RETIREMENT OBLIGATIONS (Note 6)	184,699	171,866
FUTURE INCOME TAXES (Note 14)	110,112	75,628

TRUST UNITHOLDERS EQUITY		
Trust Unitholders capital (Note 10)	2,514,997	2,383,284
Contributed surplus (Note 10)	3,646	1,923
Deficit (Note 9)	(1,042,647)	(922,996)
	1,475,996	1,462,211
COMMITMENTS (Note 18)		
SUBSEQUENT EVENT (Note 19)		
	$ 2,391,432	$ 2,276,534

See accompanying notes to the consolidated financial statements.

PENGROWTH ENERGY TRUST
CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT
(Stated in thousands of dollars)

	Year ended December 31	
	2005 (unaudited)	2004 (audited)
REVENUES		
Oil and gas sales	$ 1,151,510	$ 815,751
Processing and other income	15,091	12,390
Royalties, net of incentives	(213,863)	(160,351)
	952,738	667,790
Interest and other income	2,596	1,770
NET REVENUE	955,334	669,560
EXPENSES		
Operating	218,115	159,742
Transportation	7,891	8,274
Amortization of injectants for miscible floods	24,393	19,669
Interest	21,642	29,924
General and administrative	30,272	24,448
Management fee (Note 15)	15,961	12,874
Foreign exchange gain (Note 12)	(6,966)	(17,300)
Depletion and depreciation	284,989	247,332
Accretion (Note 6)	14,162	10,642
	610,459	495,605
NET INCOME BEFORE TAXES	344,875	173,955
INCOME TAX EXPENSE (Note 14)		
Capital	6,273	4,594
Future	12,276	15,616
	18,549	20,210
NET INCOME	$ 326,326	$ 153,745
Deficit, beginning of year	(922,996)	(713,680)
Distributions paid or declared	(445,977)	(363,061)

DEFICIT, END OF YEAR		$ (1,042,647)	$ (922,996)
NET INCOME PER TRUST UNIT (Note 16)	**Basic**	$ 2.077	$ 1.153
	Diluted	$ 2.066	$ 1.147

See accompanying notes to the consolidated financial statements.

PENGROWTH ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOW
(Stated in thousands of dollars)

	Year ended December 31	
	2005 (unaudited)	2004 (audited)
CASH PROVIDED BY (USED FOR):		
OPERATING		
Net income	$ 326,326	$ 153,745
Depletion, depreciation and accretion	299,151	257,974
Future income taxes	12,276	15,616
Contract liability amortization	(5,795)	(4,164)
Amortization of injectants	24,393	19,669
Purchase of injectants	(34,658)	(20,415)
Expenditures on remediation	(7,353)	(4,440)
Unrealized foreign exchange gain (Note 12)	(7,800)	(18,900)
Trust unit based compensation (Note 10)	2,932	2,264
Deferred charges (Note 11)	(4,961)	
Amortization of deferred charges (Note 11)	3,726	1,893
Gain on sale of marketable securities		(248)
Changes in non-cash operating working capital (Note 13)	9,833	1,173
	618,070	404,167
FINANCING		
Distributions	(436,450)	(344,744)
Change in long-term debt, net	10,030	105,000
Note payable (Note 7)	(15,000)	(10,000)
Proceeds from issue of trust units	42,544	509,830
	(398,876)	260,086
INVESTING		
Expenditures on property acquisitions	(92,568)	(572,980)
Expenditures on property, plant and equipment	(175,693)	(161,141)
Proceeds on property dispositions	37,617	
Change in remediation trust fund	(20)	(917)
Purchase of marketable securities		(2,680)
Proceeds from sale of marketable securities		2,928
Change in non-cash investing working capital (Note 13)	1,117	2,169
	(229,547)	(732,621)

CHANGE IN CASH AND TERM DEPOSITS	(10,353)	(68,368)
CASH AND TERM DEPOSITS (BANK INDEBTEDNESS) AT BEGINNING OF YEAR	(4,214)	64,154
CASH AND TERM DEPOSITS (BANK INDEBTEDNESS) AT END OF YEAR	$ (14,567)	$ (4,214)

See accompanying notes to the consolidated financial statements.

PENGROWTH ENERGY TRUST
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2005 AND 2004

(Tabular amounts are stated in thousands of dollars except per trust unit amounts.)

1. STRUCTURE OF THE TRUST

Pengrowth Energy Trust (the Trust) is a closed-end investment trust created under the laws of the Province of Alberta pursuant to a Trust Indenture dated December 2, 1988 (as amended) between Pengrowth Corporation (Corporation) and Computershare Trust Company of Canada (Computershare). Operations commenced on December 30, 1988. The beneficiaries of the Trust are the holders of trust units (the unitholders).

The purpose of the Trust is to directly and indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities, royalty units, and notes issued by the Corporation. The activities of Corporation and its subsidiaries are financed by issuance of royalty units and interest bearing notes to the Trust and third party debt. The Trust owns approximately 99.99 percent of the royalty units and 91 percent of the common shares of Corporation. The Trust, through the royalty ownership, obtains substantially all the economic benefits of Corporation. Under the terms of the Royalty Indenture, the Corporation is entitled to retain a one percent share of royalty income and all miscellaneous income (the Residual Interest) to the extent this amount exceeds the aggregate of debt service charges, general and administrative expenses, and management fees. In 2005 and 2004, this Residual Interest, as computed, did not result in any income retained by Corporation.

The royalty units and notes of Corporation held by the Trust entitle it to the net income generated by the Corporation and its subsidiaries petroleum and natural gas properties less amounts withheld in accordance with prudent business practices to provide for future Operating Costs and Reclamation Obligations, as defined in the Royalty Indenture. In addition, unitholders are entitled to receive the net income from other investments that are held directly by the Trust.

Pursuant to the Royalty Indenture, the Board of Directors of Corporation can establish a reserve for certain items including up to 20 percent of Gross Revenue to fund future capital expenditures or for the payment of royalty income in any future period.

Pursuant to the Trust Indenture, Trust unitholders are entitled to monthly distributions from interest income on the notes, royalty income under the Royalty Indenture and from other investments held directly by the Trust, less any reserves and certain expenses of the Trust including General and Administrative costs as defined in the Trust Indenture.

The Board of Directors has general authority over the business and affairs of the Corporation and derives its authority in respect to the Trust by virtue of the delegation of powers by the trustee to the Corporation as Administrator in accordance with the Trust Indenture.

Pengrowth Management Limited (the Manager) has responsibility for the management of the business affairs of the Corporation and the administration of the Trust and defers to the Board of Directors on all matters material to the Corporation and the Trust. Corporate Governance practices are consistent with corporations and trusts that do not have a management agreement. The Manager owns nine percent of the common shares of Corporation, and the Manager is controlled by an officer and a director of the Corporation.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The Trust s consolidated financial statements have been prepared in accordance with Generally Accepted Accounting Principles (GAAP) in Canada and they include the accounts of the Trust, the Corporation and its subsidiaries (collectively referred to as Pengrowth). All inter-entity transactions have been eliminated. These financial statements do not contain the accounts of the Manager.

The Trust owns 91 percent of the shares of Corporation and, through the royalty and notes, obtains substantially all the economic benefits of Corporation. In addition, the unitholders of the Trust have the right to elect the majority of the Board of Directors of Corporation.

Joint Interest Operations

A significant proportion of Pengrowth s petroleum and natural gas development and production activities are conducted with others and accordingly the accounts reflect only Pengrowth s proportionate interest in such activities.

Property, Plant and Equipment

Pengrowth follows the full cost method of accounting for oil and gas properties and facilities whereby all costs of developing and acquiring oil and gas properties are capitalized and depleted on the unit of production method based on proved reserves before royalties as estimated by independent engineers. The fair value of future estimated asset retirement obligations associated with properties and facilities are also capitalized and depleted on the unit of production method. The associated asset retirement obligations on future development capital costs are also included in the cost base subject to depletion. Natural gas production and reserves are converted to equivalent units of crude oil using their relative energy content.

General and administrative costs are not capitalized other than to the extent they are directly related to a successful acquisition, or to the extent of Pengrowth s working interest in capital expenditure programs to which overhead fees can be recovered from partners. Overhead fees are not charged on 100 percent owned projects.

Proceeds from disposals of oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Pengrowth places a limit on the carrying value of property, plant and equipment and other assets, which may be depleted against revenues of future periods (the ceiling test). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. The carrying value of property, plant and equipment and other assets subject to the ceiling test includes asset retirement costs.

Repairs and maintenance costs are expensed as incurred.

Goodwill

Goodwill, which represents the excess of the total purchase price over the estimated fair value of the net identifiable assets and liabilities acquired, is not amortized but instead is assessed for impairment annually or as events occur that could result in impairment. Impairment is assessed by determining the fair value of the reporting entity and comparing this fair value to the book value of the reporting entity. If the fair value of the reporting entity is less than the book value, impairment is measured by allocating the fair value of the reporting entity to the identifiable assets and liabilities of the reporting entity as if the reporting entity had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the reporting entity over the assigned values of 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 is the impairment amount. Impairment is charged to earnings in the period in which it occurs. Goodwill is stated at cost less impairment.

Injectant Costs

Injectants (mostly natural gas and ethane) are used in miscible flood programs to stimulate incremental oil recovery. The cost of hydrocarbon injectants purchased from third parties for miscible flood projects is deferred and amortized over the period of expected future economic benefit which is estimated as 24 to 30 months.

Inventory

Inventories of crude oil, natural gas and natural gas liquids are stated at the lower of average cost and net realizable value.

Asset Retirement Obligations

Pengrowth recognizes the fair value of an Asset Retirement Obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit of production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed to income in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO.

Pengrowth has placed cash in segregated remediation trust accounts to fund certain ARO for the Judy Creek properties, and the Sable Offshore Energy Project (SOEP). Contributions to these remediation trust accounts and expenditures on ARO not funded by the trust accounts are charged against actual cash distributions in the period incurred.

Income Taxes

The Trust is a taxable trust under the Canadian Income Tax Act. As income taxes are the responsibility of the individual unitholders and the Trust distributes all of its taxable income to its unitholders, no provision has been made for income taxes by the Trust in these financial statements.

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

Trust Unit Compensation Plans

Pengrowth has trust unit based compensation plans, which are described in Note 10. Compensation expense associated with trust unit based compensation plans is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The amount of compensation expense and contributed surplus is reduced for options, rights and deferred entitlement trust units (DEU s) that are cancelled prior to vesting. Any consideration received upon the exercise of trust unit based compensation together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in trust unitholders capital. Compensation expense is based on the estimated fair value of the trust unit based compensation at the date of grant, as further described in Note 10.

Pengrowth does not have any outstanding trust unit compensation plans that call for settlement in cash or other assets. Grants of such items, if any, will be recorded as expenses and liabilities based on the intrinsic value.

Risk Management

Financial instruments are utilized by Pengrowth to manage its exposure to commodity price fluctuations, foreign currency and interest rate exposures. Pengrowth s practice is not to utilize financial instruments for trading or speculative purposes.

Pengrowth formally documents relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. Pengrowth also formally assesses, both at the hedge s inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair value or cash flows of hedged items.

Pengrowth uses forward, futures and swap contracts to manage its exposure to commodity price fluctuations. The net receipts or payments arising from these contracts are recognized in income as a component of oil and gas sales during the same period as the corresponding hedged position.

Foreign exchange gains and losses on foreign currency exchange swaps used to hedge U.S. dollar denominated sales are recognized in income as a component of natural gas sales during the same period as the corresponding hedged position.

Foreign exchange swaps were used to fix the foreign exchange rate on the interest and principal of the £50 million ten year senior unsecured notes (see Note 17). Unrealized foreign exchange gains and losses on the debt and related hedge are recorded as the exchange rate changes.

Measurement Uncertainty

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended.

The amounts recorded for depletion, depreciation, amortization of injectants, goodwill and ARO are based on estimates. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

Earnings Per Trust Unit

In calculating diluted net income per trust unit, Pengrowth follows the treasury stock method to determine the dilutive effect of trust unit based compensation plans and other dilutive instruments. Under the treasury stock method, only in the money dilutive instruments impact the diluted calculations.

Cash and Term Deposits

Pengrowth considers term deposits with an original maturity of three months or less to be cash equivalents.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when the product is delivered. Revenue from processing and other miscellaneous sources is recognized upon completion of the relevant service.

Comparative Figures

Certain comparative figures have been reclassified to conform to the presentation adopted in the current year.

3. REMEDIATION TRUST FUNDS

Pengrowth is required to make contributions to a remediation trust fund that is used to cover certain ARO of the Judy Creek properties. Pengrowth makes monthly contributions to the fund of $0.10 per boe of production from the Judy Creek properties and an annual lump sum contribution of $250,000.

Every five years Pengrowth must evaluate the assets in the trust fund and the outstanding ARO, and make recommendations to the former owner of the Judy Creek properties as to whether contribution levels should be changed. In 2004 an evaluation was completed with the results of the evaluation determining that current funding levels would remain unchanged until the next evaluation in 2007. Contributions to the Judy Creek remediation trust fund may change based on future evaluations of the fund.

Pengrowth is required, pursuant to various agreements with the SOEP partners, to make contributions to a remediation trust fund that will be used to fund the ARO of the SOEP properties and facilities. Pengrowth makes monthly contributions to the fund of $0.04 per mcf of natural gas production and $0.08 per boe of natural gas liquids production from SOEP.

The following summarizes Pengrowth s trust fund contributions for 2005 and 2004 and Pengrowth s expenditures on ARO not covered by the trust funds:

	2005	2004
Contributions to Judy Creek Remediation Trust Fund	$ 778	$ 906
Contributions to SOEP Environmental Restoration Fund	556	548
Expenditures related to Judy Creek Remediation Trust Fund	(1,314)	(537)
	20	917
Expenditures on ARO not covered by the trust funds	6,039	3,903
Expenditures on ARO covered by the trust funds	1,314	537
	7,353	4,440
Total trust fund contributions and ARO expenditures not covered by the trust funds	$ 7,373	$5,357

4. ACQUISITIONS

Corporate Acquisitions

On April 29, 2005, Pengrowth acquired all of the issued and outstanding shares of Crispin Energy Inc. (Crispin) which held interests in oil and natural gas assets mainly in Alberta. The shares were acquired on the basis of exchanging 0.0725 Class B trust units of the Trust for each share held by Canadian resident shareholders of Crispin and 0.0512 Class A trust units of the Trust for each share held by non-Canadian resident shareholders of Crispin. The average value assigned to each trust unit issued was $20.80 based on the weighted average trading price of the Class A and Class B trust units for a period before and after the acquisition was announced. The Trust issued 3,538,581 Class B trust units and 686,732 Class A trust units valued at $88 million. The transaction was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration as follows:

Allocation of purchase price:

Working capital	$ 1,655
Property, plant, and equipment	121,729
Goodwill	12,216
Bank debt	(20,459)
Asset retirement obligations	(4,038)
Future income taxes	(22,208)
	$ 88,895

Cost of acquisition:

Trust units issued	$ 87,960
Acquisition costs	935
	$ 88,895

Property, plant and equipment of $122 million represents the estimated fair value of the assets acquired determined in part by an independent reserve evaluation. Goodwill of $12 million, which is not deductible for tax purposes, was determined based on the excess of the total cost of the acquisition less the value assigned to the identifiable assets and liabilities, including the future income tax liability.

The future income tax liability was determined based on an enacted income tax rate of approximately 34 percent as at April 29, 2005. Results from operations of the acquired assets of Crispin subsequent to April 29, 2005 are included in the consolidated financial statements.

On May 31, 2004, Pengrowth acquired all of the issued and outstanding shares of a company which had interests in oil and natural gas assets in Alberta and Saskatchewan (the Murphy acquisition). The transaction was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:

Working capital	$ 9,310
Property, plant, and equipment	502,924
Goodwill	170,619
Asset retirement obligations	(43,876)
Future income taxes	(60,012)
Contract liabilities	(28,175)
	$550,790

Cost of acquisition:

Cash and term deposits	$224,700
Acquisition facility	325,000

Acquisition costs	1,090
	$550,790

Property, plant and equipment of $503 million represents the fair value of the assets acquired determined in part by an independent reserve evaluation, net of purchase price adjustments.

Goodwill of $171 million, which is not deductible for tax purposes, was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

The future income tax liability was determined based on the enacted income tax rate of approximately 34 percent as at May 31, 2004.

Contract liabilities include a natural gas fixed price sales contract (see Note 17) and firm pipeline demand charge contracts. The fair value of these liabilities was determined on the date of acquisition and is being reduced as the contracts are settled. As at December 31, 2005 a net liability of S12.3 million (2004 $17.9 million) has been recorded for the natural gas fixed price sales contract and $5.9 million (2004 $6.1 million) has been recorded for the firm pipeline demand charge contracts.

Results of operations from the Murphy acquisition subsequent to May 31, 2004 are included in the consolidated financial statements.

The following unaudited pro forma information provides an indication of what Pengrowth s results of operations might have been had the Murphy acquisition taken place on January 1 of 2004:

	2004 Pro Forma (unaudited)	2004 Actual (audited)
Oil and gas sales	$ 897,397	$815,751
Net income	$ 180,101	$153,745
Net income per trust unit:		
Basic	$ 1.206	$ 1.153
Diluted	$ 1.201	$ 1.147

Property Acquisitions

In February 2005, Pengrowth acquired an additional 11.9 percent working interest in Swan Hills for a purchase price of $87 million before adjustments. The acquisition increased Pengrowth s working interest in the Swan Hills Unit No. 1 to 22.3 percent.

In August 2004, Pengrowth acquired an additional 34.4 percent working interest in Kaybob Notikewin Unit No. l for a purchase price of $20 million before adjustments. The acquisition increased Pengrowth s working interest in the Kaybob Notikewin Unit No.l to approximately 99 percent.

5. PROPERTY, PLANT AND EQUIPMENT AND OTHER ASSETS

	2005	2004
Property, Plant and Equipment		
Property, Plant and Equipment, at cost	$ 3,340,106	$ 2,986,681
Accumulated depletion and depreciation	(1,307,424)	(1,022,435)
Net book value of property, plant and equipment	2,032,682	1,964,246
Other Assets		
Deferred injectant costs	35,306	25,042
Net book value of property, plant and equipment and other assets	$ 2,067,988	$ 1,989,288

Property, plant and equipment includes $77.3 million (2004 $81.1 million) related to ARO, net of accumulated depletion.

Pengrowth performed a ceiling test calculation at December 31, 2005 to assess the recoverable value of the property, plant and equipment and other assets. The oil and gas future prices are based on the January 1, 2006 commodity price forecast of our independent reserve evaluators. These prices have been adjusted for commodity price differentials specific to Pengrowth. The following table summarizes the benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of future net revenues from Pengrowth s proved reserves exceeded the carrying value of property, plant and equipment and other assets at December 31, 2005.

Year	WTI Oil (U.S.$/bbl)	Foreign Exchange Rate (U.S.$/Cdn$)	Edmonton Light Crude Oil (Cdn$/bbl)	AECO Gas (Cdn$/mmbtu)
2006	57.00	0.85	66.25	10.60
2007	55.00	0.85	64.00	9.25
2008	51.00	0.85	59.25	8.00
2009	48.00	0.85	55.75	7.50
2010	46.50	0.85	54.00	7.20
2011	45.00	0.85	52.25	6.90
2012	45.00	0.85	52.25	6.90
2013	46.00	0.85	53.25	7.05
2014	46.75	0.85	54.25	7.20
2015	47.75	0.85	55.50	7.40
2016	48.75	0.85	56.50	7.55
Escalate thereafter	2.0% per year		2.0% per year	2.0% per year

6. ASSET RETIREMENT OBLIGATIONS

The total future ARO were estimated by management based on Pengrowth s working interest in wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. Pengrowth has estimated the net present value of its ARO to be $185 million as at December 31, 2005 (2004 $172 million), based on a total escalated future liability of $1,041 million (2004 $551 million). These costs are expected to be made over 50 years with the majority of the costs incurred between 2032 and 2054. Pengrowth s credit adjusted risk free rate of eight percent (2004 eight percent) and an inflation rate of 2.0 percent (2004 1.5 percent) were used to calculate the net present value of the ARO.

The following reconciles Pengrowth s ARO:

	2005	2004
Asset retirement obligations, beginning of year	$171,866	$102,528
Increase (decrease) in liabilities during the year related to:		
Acquisitions	6,347	44,368
Disposals	(3,844)	
Additions	1,972	2,681
Revisions	1,549	16,087
Accretion expense	14,162	10,642
Liabilities settled during the year	(7,353)	(4,440)

Asset retirement obligations, end of year	$184,699	$171,866

7. NOTE PAYABLE

The note payable is due to Emera Offshore Incorporated, in respect of the acquisition of the SOEP facility in 2003. The note payable is secured by Pengrowth s working interest in SOEP. The note payable is non-interest bearing with the final payment of $20 million due on December 31, 2006.

At December 31, 2005, $0.7 million (2004 $2.0 million) has been recorded as a deferred charge representing the imputed interest on the non-interest bearing note. This amount will be recognized as interest expense over the term of the note.

8. LONG TERM DEBT

	2005	2004
U.S. dollar denominated debt:		
U.S. dollar $150 million senior unsecured notes at 4.93 percent due April 2010	$174,450	$180,300
U.S. dollar $50 million senior unsecured notes at 5.47 percent due April 2013	58,150	60,100
	232,600	240,400
Pound sterling denominated £50 million unsecured notes at 5.46 percent due December 2015	100,489	
Canadian dollar revolving credit borrowings	35,000	105,000
	$368,089	$345,400

On April 23, 2003, Pengrowth closed a U.S. $200 million private placement of senior unsecured notes. The notes were offered in two tranches of U.S. $150 million at 4.93 percent due April 2010 and U.S. $50 million at 5.47 percent due in April 2013. The notes contain certain financial maintenance covenants and interest is paid semi-annually. Costs incurred in connection with issuing the notes, in the amount of $2.1 million are being amortized over the term of the notes (see Note 11).

On December 1, 2005 Pengrowth closed a £50 million private placement of senior unsecured notes. In a series of related hedging transactions, Pengrowth fixed the pound sterling to Canadian dollar exchange rate for all the semi-annual interest payments and the principal repayments at maturity. The notes have an effective rate of 5.49 percent after the hedging transactions. The notes contain the same financial maintenance covenants as the U.S. dollar denominated notes. Costs incurred in connection with issuing the notes, in the amount of $0.7 million are being amortized over the term on the notes (see Note 11).

The Corporation has a $370 million revolving unsecured credit facility syndicated among eight financial institutions with an extendible 364 day revolving period and a three year amortization term period. The facilities are currently reduced by outstanding letters of credit in the amount of approximately $17 million. In addition, it has a $35 million demand operating line of credit. Interest payable on amounts drawn is at the prevailing bankers acceptance rates plus stamping fees, lenders prime lending rates, or U.S. LIBOR rates plus applicable margins, depending on the form of borrowing by the Corporation. The margins and stamping fees vary from zero percent to 1.4 percent depending on financial statement ratios and the form of borrowing.

The revolving credit facility will revolve until June 16, 2006, whereupon it may be renewed for a further 364 days, subject to satisfactory review by the lenders, or converted into a term facility. If converted to a term facility, one third of the amount outstanding would be repaid in equal quarterly instalments in each of the first two years with the final one third to be repaid upon maturity of the term period. The Corporation can post, at its option, security suitable to the banks in lieu of the first year s payments. In such an instance, no principal payment would be made to the banks for one year following the date of non-renewal.

The five year schedule of long term debt repayment based on maturity is as follows: 2006 nil, 2007 nil, 2008 nil, 2009 nil, 2010 $174.45 million.

9. DEFICIT

	2005	2004
Accumulated earnings	$ 1,053,383	$ 727,057
Accumulated distributions paid or declared	(2,096,030)	(1,650,053)
	$(1,042,647)	$ (922,996)

Pengrowth is obligated by virtue of its Royalty and Trust Indentures to distribute to unitholders a significant portion of its cash flow from operations. Cash flow from operations typically exceeds net income as a result of non cash expenses such as depletion, depreciation and accretion. These non cash expenses result in a deficit being recorded despite Pengrowth distributing less than its cash flow from operations.

10. TRUST UNITS

The total authorized capital of Pengrowth is 500,000,000 trust units.

Total Trust Units:

	Year Ended December 31, 2005		Year Ended December 31, 2004	
Trust units issued	Number of trust units	Amount	Number of trust units	Amount
Balance, beginning of year	152,972,555	$2,383,284	123,873,651	$1,872,924
Issued for cash			26,885,000	499,480
Less: issue expenses				(26,287)
Issued for the Crispin acquisition (non-cash) (Note 4)	4,225,313	87,960		
Issued for cash on exercise of trust unit options and rights	1,512,211	21,818	1,294,838	20,251
Issued for cash under Distribution Reinvestment Plan (DRIP)	1,154,004	20,726	918,366	16,386
Trust unit rights incentive plan (non-cash exercised)		1,209		530
Royalty units exchanged for trust units			700	
Balance, end of year	159,864,083	$2,514,997	152,972,555	$2,383,284

Class A Trust Units:

	Year Ended December 31, 2005	For the period from July 27, 2004 to Dec 31, 2004

Trust units issued	Number of trust units	Amount	Number of trust units	Amount
Balance, beginning of period	76,792,759	$1,176,427		$
Issued for the Crispin acquisition (non-cash) (Note 4)	686,732	19,002		
Trust units converted	45,182	692	76,792,759	1,176,427
Balance, end of period	77,524,673	$1,196,121	76,792,759	$1,176,427

Class B Trust Units:

Trust units issued	Year Ended December 31, 2005 Number of trust units	Year Ended December 31, 2005 Amount	For the period from July 27, 2004 to Dec 31, 2004 Number of trust units	For the period from July 27, 2004 to Dec 31, 2004 Amount
Balance, beginning of period	76,106,471	$1,205,734		$
Trust units converted	(9,824)	(151)	59,000,129	903,854
Issued for cash			15,985,000	298,920
Less: issue expenses				(15,577)
Issued for the Crispin acquisition (non-cash) (Note 4)	3,538,581	68,958		
Issued for cash on exercise of trust unit options and rights	1,512,211	21,818	746,864	11,516
Issued for cash under Distribution Reinvestment Plan (DRIP)	1,154,004	20,726	374,478	6,750
Trust unit rights incentive plan (non-cash exercised)		1,209		271
Balance, end of period	82,301,443	$1,318,294	76,106,471	$1,205,734

Unclassified Trust Units:

Trust Units Issued	Year Ended December 31, 2005 Number of units	Year Ended December 31, 2005 Amount	Year Ended December 31, 2004 Number of units	Year Ended December 31, 2004 Amount
Balance, beginning of year	73,325	$1,123	123,873,651	$ 1,872,924
Issued for cash			10,900,000	200,560
Less: issue expenses				(10,710)
Issued for cash on exercise of trust unit options and rights			547,974	8,735
Issued for cash under Distribution Reinvestment Plan (DRIP)			543,888	9,636
Trust unit rights incentive plan (non-cash exercised)				259
Royalty units exchanged for trust units			700	
Balance, prior to conversion			135,866,213	$ 2,081,404
Converted to Class A or Class B trust units	(35,358)	(541)	(135,792,888)	(2,080,281)
Balance, end of year	37,967	$ 582	73,325	$ 1,123

On July 27, 2004 Pengrowth implemented a reclassification of its trust units whereby the existing outstanding trust units were reclassified into Class A or Class B trust units depending on the residency of the unitholder. Of the original trust units, 37,967 are undeclared trust units that have not been classified as Class A or Class B trust units as the unitholders of these trust units have not submitted a declaration of residency certificate.

The Class A trust units and the Class B trust units have the same rights to vote and obtain distributions upon wind-up or dissolution of the Trust. The most significant distinction between the two classes of units is in respect of residency of the persons entitled to hold and trade the Class A trust units and Class B trust units.

Class A trust units are not subject to any residency restriction but are subject to a restriction on the number to be issued such that the total number of issued and outstanding Class A trust units will not exceed 99 percent of the number issued and outstanding Class B trust units after an initial implementation period (the Ownership Threshold). Class A trust units may be converted by a holder at any time into Class B trust units provided that the holder is a resident of Canada and provides a suitable residency declaration. Class A trust units trade on both the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE).

Class B trust units may not be held by non-residents of Canada and trade only on the TSX. Class B trust units may be converted by a holder into Class A trust units, provided that the Ownership Threshold will not be exceeded.

If the number of issued and outstanding Class A trust units exceeds the Ownership Threshold, the Trust may make a public announcement of the contravention and enforce one or several available options to reduce the number of Class A trust units to the Ownership Threshold, as outlined in the Trust Indenture.

If it appears from the securities registers, or if the Board of Directors of Corporation determines, that a person that is a non-resident of Canada holds or beneficially owns any Class B trust units, Pengrowth shall send a notice to the registered holder(s) of the Class B trust units requiring such holder(s) to dispose of the Class B trust units and pending such disposition may suspend all rights of ownership attached to such units, including the rights to receive distributions.

Following the reclassification, the number of outstanding Class A trust units exceeded the Ownership Threshold. On December 1, 2004, Pengrowth received a letter from the Canada Revenue Agency that extended the date by which Pengrowth must comply with the Ownership Threshold to June 1, 2005. Pengrowth complied with the Ownership Threshold on April 29, 2005 and continued to comply with the Ownership Threshold as of February 27, 2006.

Certain provisions exist that could prevent exclusionary offers being made for only one class of trust units in existence at the time of the original offer. In the event that an offer is made for only one class of trust units; in certain circumstances the Ownership Threshold would temporarily cease to apply.

Pursuant to the terms of the Royalty Indenture and the Trust Indenture, there is attached to each royalty unit granted by the Corporation to royalty unitholders other than the Trust the right to exchange such royalty unit for an equivalent number of trust units. Accordingly, Computershare as Trustee has reserved 18,240 trust units for such future conversion.

Distribution Reinvestment Plan

Class B unitholders are eligible to participate in the Distribution Reinvestment Plan (DRIP). DRIP entitles the unitholder to reinvest cash distributions in additional units of the Trust. The trust units under the plan are issued from treasury at a five percent discount to the weighted average closing price of all Class B trust units traded on the TSX for the 20 trading days preceding a distribution payment date. Class A unitholders are not eligible to participate in DRIP. Trust units issued on the exercise of options and rights under Pengrowth s unit based compensation plans are Class B trust units.

Contributed Surplus

	2005	2004
Balance, beginning of year	$ 1,923	$ 189
Trust unit rights incentive plan (non-cash expensed)	1,740	2,264
Deferred entitlement trust units	1,192	
Trust unit rights incentive plan (non-cash exercised)	(1,209)	(530)
Balance, end of year	$ 3,646	$1,923

Trust Unit Option Plan

Pengrowth has a trust unit option plan under which directors, officers, employees and special consultants of the Corporation and the Manager are eligible to receive options to purchase Class B trust units. No new grants have been issued under the plan since November 2002. Under the terms of the plan, up to ten percent of the issued and outstanding trust units, to a maximum of ten million trust units, may be reserved for option and right grants. The options expire seven years from the date of grant. One third of the options vest on the grant date, one third on the first anniversary of the date of grant, and the remaining third on the second anniversary.

As at December 31, 2005, options to purchase 259,317 Class B trust units were outstanding (2004 845,374) that expire at various dates to June 28, 2009.

	2005		2004	
Trust Unit Options	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding at beginning of year	845,374	$ 16.97	2,014,903	$ 17.47
Exercised	(558,307)	$ 16.74	(838,789)	$ 16.82
Expired	(27,750)	$ 18.63	(325,200)	$ 20.44
Cancelled			(5,540)	$ 16.53
Outstanding at year-end	259,317	$ 17.28	845,374	$ 16.97
Exercisable at year-end	259,317	$ 17.28	845,374	$ 16.97

The following table summarizes information about trust unit options outstanding and exercisable at December 31, 2005:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number Outstanding and Exercisable	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price
$12.00 to $14.99	30,193	2.9	$ 13.08
$15.00 to $16.99	38,139	2.7	$ 15.05
$17.00 to $17.99	82,772	2.4	$ 17.47
$18.00 to $20.50	108,213	1.9	$ 19.09
$12.00 to $20.50	259,317	2.3	$ 17.28

Trust Unit Rights Incentive Plan

Pengrowth has a Trust Unit Rights Incentive Plan (Rights Incentive Plan), pursuant to which rights to acquire Class B trust units may be granted to the directors, officers, employees, and special consultants of the Corporation and the Manager. Under the Rights Incentive Plan, distributions per trust unit to unitholders in a calendar quarter which represent a return of more than 2.5 percent of the net book value of property, plant and equipment at the beginning of such calendar quarter result, at the discretion of the holder, in a reduction in the exercise price. Total price reductions calculated for 2005 were $1.49 per trust unit right (2004 $1.30 per trust unit right). One third of the rights granted under the Rights Incentive Plan vest on the grant date, one third on the first anniversary date of the grant and the remaining on the second anniversary. The rights have an expiry date of five years from the date of grant.

As at December 31, 2005, rights to purchase 1,441,737 Class B trust units were outstanding (2004 2,011,451) that expire at various dates to November 21, 2010.

Trust Unit Rights	2005 Number of rights	2005 Weighted average exercise price	2004 Number of rights	2004 Weighted average exercise price
Outstanding at beginning of year	2,011,451	$ 14.23	1,112,140	$ 12.20
Granted (1)	606,575	$ 18.34	1,409,856	$ 17.35
Exercised	(953,904)	$ 12.81	(456,049)	$ 13.47
Cancelled	(222,385)	$ 16.19	(54,496)	$ 14.19
Outstanding at year-end	1,441,737	$ 14.85	2,011,451	$ 14.23
Exercisable at year-end	668,473	$ 13.73	1,037,078	$ 12.48

(1) Weighted average exercise price of rights granted are based on the exercise price at the date of grant.

The following table summarizes information about trust unit rights outstanding and exercisable at December 31, 2005:

	Rights Outstanding			Rights Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$8.97 to $13.99	199,280	1.9	$ 9.03	199,280	$ 9.03
$14.00 to $15.99	549,620	3.1	$ 14.01	223,339	$ 14.01
$16.00 to $17.99	571,505	3.9	$ 16.89	206,942	$ 17.04
$18.00 to $20.99	121,332	4.8	$ 18.65	38,912	$ 18.68
$8.97 to $20.99	1,441,737	3.1	$ 14.85	668,473	$ 13.73

Fair Value of Unit Based Compensation

Pengrowth records compensation expense on trust unit rights granted on or after January 1, 2003. For trust unit options and rights granted in 2002, Pengrowth has elected to disclose the pro forma effect on net income had compensation expense been recorded using the fair value method. All of the trust unit options and rights issued in 2002 were fully vested prior to 2005, therefore there is no pro forma effect on net income for 2005. The following is the pro forma effect on net income in 2004:

	2004
Net income	$153,745
Compensation expense related to rights incentive options granted in 2002	(1,067)

Pro forma net income	$152,678
Pro forma net income per trust unit:	
Basic	$ 1.145
Diluted	$ 1.139

The fair value of trust unit rights granted in 2005 and 2004 was estimated at 15 percent of the exercise price at the date of grant using a modified Black-Scholes option pricing model with the following assumptions: risk-free rate of 3.9 percent, volatility of 19 percent (2004 22 percent), expected life of five years and adjustments for the estimated distributions and reductions in the exercise price over the life of the trust unit rights.

Long Term Incentive Program

Effective January 1, 2005, the Board of Directors approved a Long Term Incentive Plan. The DEU s issued under the plan fully vest and are converted to Class B trust units on the third anniversary year from the date of grant and will receive deemed distributions prior to the vesting date in the form of additional DEU s. However, the number of DEU s actually issued to each participant at the end of the three year vesting period will be subject to a relative performance test which compares Pengrowth s three year average total return to the three year average total return of a peer group of other energy trusts such that upon vesting, the number of Class B trust units issued from treasury may range from zero to one and one-half times the number of DEU s granted plus accrued DEU s through the deemed reinvestment of distributions. Compensation expense related to DEU s is based on the fair value of the DEU s at the date of grant. The number of Class B trust units awarded at the end of the vesting period is subject to certain performance conditions. Compensation expense incorporates the estimated fair value of the DEU s at the date of grant and an estimate of the relative performance multiplier. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions. An estimate of forfeiture has not been made; rather compensation expense is reduced for actual forfeitures as they occur. Compensation expense is recognized in income over the vesting period with a corresponding increase or decrease to Contributed Surplus. Upon issuance of the Class B trust units at the end of the vesting period, trust unit holders capital is increased and contributed surplus is reduced. For the 12 months ended December 31, 2005, Pengrowth recorded compensation expense of $1.2 million associated with the DEU s. Compensation expense associated with the DEU s was based on the weighted average estimated fair value of $18.32 per DEU.

	Number of DEU s
Outstanding, beginning of period	
Granted	194,229
Cancelled	(26,258)
Deemed DRIP	17,620
Outstanding, end of period	185,591

Trust Unit Award Plan

Effective July 13, 2005, Pengrowth established an incentive plan to reward and retain employees whereby Class B trust units and cash were awarded to eligible employees. Employees received one half of the trust units and cash on or about January 1, 2006 and will receive one half of the trust units and cash on or about July 1, 2006. Any change in the market value of the Class B trust units and reinvested distributions over the vesting period accrues to the eligible employees.

Pengrowth acquired the Class B trust units to be awarded under the plan on the open market for $4.3 million and placed them in a trust account established for the benefit of the eligible employees. The cost to acquire the trust units has been recorded as deferred compensation expense and is being charged to net income on a straight line basis over one year. In addition, the cash portion of the incentive plan of approximately $1.5 million is being accrued on a straight line basis over one year. Any unvested trust units will be sold on the open market. During the six months ended December 31, 2005 $2.9 million has been charged to net income.

Employee Savings Plans

Pengrowth has savings plans whereby Pengrowth will match contributions by qualifying employees of zero to ten percent of their annual basic salary, less any of Pengrowth s contributions to the Group Registered Retirement Savings Plan (Group RRSP), to purchase trust units in the open market. Participants in the Group RRSP can make contributions from one to 13 percent and Pengrowth will match contributions to a maximum of five percent of their annual basic salary. Pengrowth s share of contributions to the Trust Unit Purchase Plan and Group RRSP were $1.5 million in 2005 (2004 $1.3 million) and $0.5 million in 2005 (2004 $0.4 million), respectively.

Trust Unit Margin Purchase Plan

Pengrowth has a plan whereby the employees and certain consultants of Pengrowth and the Manager can purchase trust units and finance up to 75 percent of the purchase price through an investment dealer, subject to certain participation limits and restrictions. Certain officers and directors hold trust units under the Trust Unit Margin Purchase Plan; however, they are prohibited from increasing the number of trust units they can hold under the plan. Participants maintain personal margin accounts with the investment dealer and are responsible for all interest costs and obligations with respect to their margin loans.

Pengrowth has provided a $1 million letter of credit (2004 $5 million) to the investment dealer to guarantee amounts owing with respect to the plan. The amount of the letter of credit may fluctuate depending on the amounts financed pursuant to the plan. At December 31, 2005, 721,334 Class B trust units were deposited under the plan (2004 848,022) with a market value of $16.3 million (2004 $15.7 million) and a corresponding margin loan of $2.7 million (2004 $3.1 million).

The investment dealer has limited the total margin loan available under the plan to the lesser of $15 million or 35 percent of the market value of the units held under the plan. If the market value of the trust units under the plan declines, Pengrowth may be required to make payments or post additional letters of credit to the investment dealer. Any payments to be made by Pengrowth are to be reduced by proceeds of liquidating the individual s trust units held under the plan. The maximum amount Pengrowth may be required to pay at December 31, 2005 was $2.7 million (2004 $3.1 million), the fair value of which is estimated to be a nominal amount.

Redemption Rights

Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 95 percent of the market trading price of the Class B trust units traded on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price of the Class B trust units quoted on the TSX on the date the trust units have been surrendered for redemption. Trust units can be redeemed for cash to a maximum of $25,000 per month. Redemptions in excess of the cash limit must be satisfied by way of a distribution *in specie* of a pro-rata share of royalty units and other assets, excluding facilities, pipelines or other assets associated with oil and natural gas production, which are held by the Trust at the time the trust units are to be redeemed.

11. DEFERRED CHARGES

	2005	2004
Imputed interest on note payable (net of accumulated amortization of $2,859, 2004 $1,587)	$ 748	$2,020
U.S. debt issue costs (net of accumulated amortization of $816, 2004 $510)	1,325	1,631
Deferred compensation expense (net of accumulated amortization of $2,143, 2004 nil)	2,141	
U.K. debt issue costs (net of accumulated amortization of $5)	672	
	$4,886	$3,651

12. FOREIGN EXCHANGE LOSS (GAIN)

	2005	2004
Unrealized foreign exchange gain on translation of U.S. dollar denominated debt	$(7,800)	$(18,900)
Realized foreign exchange losses	834	1,600
	$(6,966)	$(17,300)

The U.S. dollar denominated debt is translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in income.

13. OTHER CASH FLOW DISCLOSURES

Change in Non-Cash Operating Working Capital

Cash provided by (used for):	2005	2004
Accounts receivable	$(21,511)	$(22,515)
Inventory	439	260
Accounts payable and accrued liabilities	29,953	17,225
Due to Pengrowth Management Limited	952	6,203
	$ 9,833	$ 1,173

Change in Non-Cash Investing Working Capital

Cash provided by:	2005	2004
Accounts payable for capital accruals	$1,117	$2,169

Cash payments

	2005	2004
Cash payments made for taxes[(1)]	$ 6,424	$ 4,729
Cash payments made for interest	$21,779	$28,119

(1) Capital and resource taxes

14. INCOME TAXES

In 2003, the federal government implemented a reduction in federal corporate income tax rates that is being phased in over a period of five years commencing 2003. The applicable tax rate on resource income will be reduced from 28 percent to 21 percent. Additionally, crown royalties will be an allowable deduction and the resource allowance will be eliminated.

As a result of the changes to the income tax rates, Pengrowth s future tax rate applied to the temporary differences is approximately 34 percent in 2005 (34 percent in 2004) compared to the federal and provincial statutory rate of approximately 38 percent for the 2005 income tax year. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to Pengrowth s income before taxes.

	2005	2004
Income before taxes	$ 344,875	$173,955
Combined federal and provincial tax rate	37.6%	38.6%
Expected income tax	129,673	67,147
Net income of the Trust	(122,698)	(59,346)
Resource allowance	(10,985)	(8,807)
Non-deductible crown charges	22,756	16,476
Unrealized foreign exchange gain	(1,623)	(3,648)
Attributed Canadian royalty income	(3,541)	(3,113)
Effect of proposed tax changes		3,850
Future tax rate difference	(1,402)	(1,585)
Change in valuation allowance		3,035
Other	96	1,607
Future income taxes	12,276	15,616
Capital taxes	6,273	4,594
	$ 18,549	$ 20,210

The net future income tax liability is comprised of:

	2005	2004
Future income tax liabilities:		
Property, plant, equipment and other assets	$114,256	$79,774
Unrealized foreign exchange gain	9,689	8,378
Other	110	
	124,055	88,152
Future income tax assets:		
Attributed Canadian royalty income	(7,819)	(4,418)
Contract liabilities	(6,124)	(8,072)
Other		(34)
	$110,112	$75,628

At December 31, 2005, the petroleum and natural gas properties and facilities owned by the corporate subsidiaries of Pengrowth have an approximate tax basis of $634 million (2004 $607 million) available for future use as deductions from taxable income.

15. RELATED PARTY TRANSACTIONS

The Manager provides certain services pursuant to a management agreement for which Pengrowth was charged $6.9 million (2004 $6.1 million) for performance fees and $9.1 million (2004 $6.8 million) for a management fee. In addition, Pengrowth was charged $0.9 million (2004 $0.8 million) for reimbursement of general and administrative expenses incurred by the Manager pursuant to the management agreement. The law firm controlled by the Vice President and Corporate Secretary charged $0.7 million (2004 $0.8 million) for legal and advisory services provided to Pengrowth. The transactions have been recorded at the exchange amount. Amounts payable to the related parties are unsecured, non-interest bearing and have no set terms of repayment.

16. AMOUNTS PER TRUST UNIT

The per trust unit amounts for net income are based on the weighted average trust units outstanding for the year. The weighted average trust units outstanding for 2005 were 157,127,181 trust units (2004 133,395,485 trust units). In computing diluted net income per trust unit, 786,577 trust units were added to the weighted average number of trust units outstanding during the year ended December 31, 2005 (2004 611,086) for the dilutive effect of trust unit options, trust unit rights and DEU s. In 2005, 409,557 (2004 741,838) trust unit options and rights were excluded from the diluted net income per unit calculation as their effect is anti-dilutive.

17. FINANCIAL INSTRUMENTS

Interest Rate Risk

Pengrowth has minimal exposure to interest rate changes as approximately 90 percent of Pengrowth s long term debt at December 31, 2005 has fixed interest rates (Note 8).

At December 31, 2005 and 2004, there were no interest rate swaps outstanding.

Foreign Currency Exchange Risk

Pengrowth is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices. Pengrowth has mitigated some of this exchange risk by entering into fixed Canadian dollar crude oil and natural gas price swaps as outlined in the forward and futures contracts section below. Pengrowth is exposed to foreign currency fluctuation on the U.S. denominated notes for both interest and principal payments. Pengrowth entered into a foreign exchange swap in conjunction with issuing £50 million of ten year term notes (Note 8) which fixed the Cdn$ to £ exchange rate on the interest and principal of the £ denominated debt at approximately £0.4976 per Canadian dollar. The estimated fair value of the foreign exchange swap has been determined based on the amount Pengrowth would receive or pay to terminate the contract at year-end. At December 31, 2005, the amount Pengrowth would pay to terminate the foreign exchange swap would be approximately $2.2 million.

At December 31, 2004, there were no foreign currency exchange swaps outstanding.

Credit Risk

Pengrowth sells a significant portion of its oil and gas to commodity marketers, and the accounts receivable are subject to normal industry credit risks. The use of financial swap agreements involves a degree of credit risk that Pengrowth manages through its credit policies which are designed to limit eligible counterparties to those with A credit ratings or better.

Forward and Futures Contracts

Pengrowth has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. Pengrowth sells forward a portion of its future production through a combination of fixed price sales contracts with customers and commodity swap agreements with financial counterparties. The forward and futures contracts are subject to market risk from fluctuating commodity prices and exchange rates.

As at December 31, 2005, Pengrowth had fixed the price applicable to future production as follows:

Crude Oil:

Remaining Term	Volume (bbl/d)	Reference Point	Price per bbl
Financial:			
Jan 1, 2006 Dec 31, 2006	4,000	WTI (1)	$64.08 Cdn

Natural Gas:

Remaining Term		Volume (mmbtu/d)	Reference Point	Price per mmbtu
Financial:				
Jan 1, 2006	Mar 31, 2006	2,500	NYMEX [(1)]	$14.56 Cdn
Jan 1, 2006	Dec 31, 2006	2,500	Transco Z6[(1)]	$10.63 Cdn
Jan 1, 2006	Dec 31, 2006	2,370	AECO	$8.03 Cdn

(1) Associated Cdn$ / U.S.$ foreign exchange rate has been fixed.

The estimated fair value of the financial crude oil and natural gas contracts has been determined based on the amounts Pengrowth would receive or pay to terminate the contracts at year end. At December 31, 2005, the amount Pengrowth would pay to terminate the financial crude oil and natural gas contracts would be $13.0 million and $5.4 million, respectively.

Natural Gas Fixed Price Sales Contract:

Pengrowth assumed a natural gas fixed price sales contract in conjunction with the Murphy acquisition. At December 31, 2005, the amount Pengrowth would pay to terminate the fixed price sales contract would be $35.3 million. Details of the physical fixed price sales contract are provided below:

Remaining Term		Volume (mmbtu/d)	Price per mmbtu[(1)]
2006 to 2009			
Jan 1, 2006	Oct 31, 2006	3,886	$2.23 Cdn
Nov 1, 2006	Oct 31, 2007	3,886	$2.29 Cdn
Nov 1, 2007	Oct 31, 2008	3,886	$2.34 Cdn
Nov 1, 2008	April 30, 2009	3,886	$2.40 Cdn

(1) Reference price based on AECO

Fair value of financial instruments

The carrying value of financial instruments included in the balance sheet, other than long term debt, the note payable and remediation trust funds approximate their fair value due to their short maturity. The fair value of the note payable at December 31, 2005 and 2004 approximated its carrying value net of the imputed interest included in deferred charges. The fair value of the other financial instruments are as follows:

	As at December 31, 2005		As at December 31, 2004	
	Fair Value	Net Book Value	Fair Value	Net Book Value
Remediation Funds	$ 9,071	$ 8,329	$ 8,366	$ 8,309
U.S. dollar denominated debt	220,187	232,600	238,726	240,400
£ denominated debt	101,257	100,489		

18. COMMITMENTS

Pengrowth has future commitments under various agreements for oil and natural gas pipeline transportation, the purchase of carbon dioxide and operating leases. The commitment to purchase carbon dioxide arises as a result of Pengrowth s working interest in the Weyburn CO_2 miscible flood project[1]. Capital expenditures arise from authorized expenditures at SOEP.

	2006	2007	2008	2009	2010	Thereafter	Total
Pipeline transportation	$43,839	$38,197	$34,981	$29,813	$11,748	$ 53,525	$212,103
Capital expenditures	33,323	7,098	294				40,715
CO_2 purchases	5,119	4,357	4,198	4,232	4,267	18,728	40,901
Other commitments	3,132	3,096	3,950	3,610	3,377	32,779	49,944
	$85,413	$52,748	$43,423	$37,655	$19,392	$105,032	$340,663

(1) Contract prices for CO_2 are denominated in U.S. dollars and have been translated at the year end foreign exchange rate.

19. SUBSEQUENT EVENT

On January 12, 2006, Pengrowth announced certain transactions with Monterey under which Pengrowth has sold oil and gas properties for $22 million of cash and eight million shares in Monterey. As at February 27, 2006 Pengrowth holds approximately 34 percent of the common shares of Monterey.

20. RECONCILIATION OF FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The significant differences between Canadian generally accepted accounting principles (Canadian GAAP) which, in most respects, conforms to generally accepted accounting principles in the United States (U.S. GAAP), as they apply to Pengrowth, are as follows:

(a) As required annually under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of future or deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at ten percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. At December 31, 1998 and 1997 the application of the full cost ceiling test under U.S. GAAP resulted in a write-down of capitalized costs of $328.6 million and $49.8 million, respectively. At December 31, 2005 and 2004, the application of the full cost ceiling test under U.S. GAAP did not result in a write-down of capitalized costs.

Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion will differ in subsequent years.

(b) Under U.S. GAAP, interest and other income would not be included as a component of Net Revenue.

(c) Effective January 1, 2003, Pengrowth prospectively adopted U.S. standards relating to recognizing the compensation expense associated with trust unit based compensation plans. Under U.S. GAAP Pengrowth adopted the following:

(i) For trust unit options granted on or after January 1, 2003, the estimated fair value of the options is recognized as an expense over the vesting period. The compensation expense associated with trust unit options granted prior to January 1, 2003 is disclosed on a pro forma basis. As of January 1, 2005 all trust unit options were fully vested, thus there is no pro forma expense disclosed for 2005.

(ii) For trust unit rights granted on or after January 1, 2003, the estimated fair value of the rights, determined using a modified Black-Scholes option pricing model, is recognized as an expense over the vesting period. The compensation expense associated with the rights granted prior to January 1, 2003 is disclosed on a pro

forma basis. As of January 1, 2005 all trust unit rights issued before January 1, 2003 are fully vested, thus there is no pro forma expense disclosed for 2005.

The following is the pro forma effect of trust unit options and rights granted prior to January 1, 2003, had the fair value method of accounting been used:

Year ended December 31,	2004
Net income (loss) U.S. GAAP, as reported	$180,045
Compensation expense related to rights incentive options granted prior to January 1, 2003	(1,067)
Pro forma net income U.S. GAAP	$178,978
Pro forma net income U.S. GAAP per trust unit:	
Basic	$ 1.34
Diluted	$ 1.34

(d) Statement of Financial Accounting Standards (SFAS) 130 requires the reporting of comprehensive income in addition to net income. Comprehensive income includes net income plus other comprehensive income; specifically, all changes in equity of a company during a period arising from non-owner sources.

(e) SFAS 133, Accounting for Derivative Instruments and Hedging Activities establishes accounting and reporting standards for derivative instruments and for hedging activities. This statement requires an entity to establish, at the inception of a hedge, the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspect of the hedge. Those methods must be consistent with the entity s approach to managing risk.

At December 31, 2005, $18.4 million has been recorded as a current liability in respect of the fair value of financial crude oil and natural gas hedges outstanding at year end with a corresponding change in accumulated other comprehensive income. At December 31, 2004, $7.3 million has been recorded as a current asset in respect of the fair value of the financial crude oil and natural gas hedges outstanding at year end with a corresponding change in accumulated other comprehensive income. These amounts will be recognized against crude oil and natural gas sales over the remaining terms of the related hedges.

At December 31, 2005, $0.3 million has been recorded as a current liability with respect to the ineffective portion of crude oil and natural gas hedges outstanding at year end, with a corresponding change in net income. At December 31, 2004, the ineffective portion of crude oil and natural gas hedges outstanding at year end was not significant.

At December 31, 2005, Pengrowth recorded a loss of $2.2 million relating to the foreign currency swap associated with the issuance of the £ denominated debt. As of February 14, 2006, Pengrowth had adequate documentation in place to account for the foreign currency contract as a hedge under U.S. GAAP.

At December 31, 2004, there were no foreign exchange swaps outstanding.

(f) Under U.S. GAAP the Trust s equity is classified as redeemable equity as the Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 95 percent of the market trading price of the Class B trust units traded on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price of the Class B trust units quoted on the TSX on the date the trust units have been surrendered for redemption. Prior to the reclassification of trust units into Class A or Class B trust units, the trust units were redeemable as described above except the redemption price was based on the market trading price of the original trust units. Trust units can be redeemed for cash to a maximum of $25,000 per month. Redemptions in excess of the cash limit must be satisfied by way of a distribution in Specie of a pro-rata share of royalty units and other assets, excluding facilities, pipelines or other assets associated with oil and natural gas production, which are held by the Trust at the time the trust units are to be redeemed.

(g) Under U.S. standards, an entity that is subject to income tax in multiple jurisdictions is required to disclose income tax expense at each jurisdiction. Pengrowth is subject to tax at the federal and provincial level. The portion of income tax expense taxed at the federal level is $12.9 million (2004 $14.8 million). The portion of income tax expense taxed at the provincial level is $5.7 million (2004 $5.4 million).

(h) In December 2004, the FASB issued SFAS 153 which deals with the accounting for the exchanges of non-monetary assets. SFAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of non-monetary assets should be measured based on the fair value of the assets exchanged. SFAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for non-monetary exchanges of similar productive assets and introduce a broader exception for exchanges of non-monetary assets that do not have commercial substance. SFAS 153 is effective for non-monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Adopting the provisions of SFAS 153 is not expected to impact the U.S. GAAP financial statements.

In December 2004, the FASB issued SFAS 123R which deals with the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity s equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123R focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. SFAS 123R is a revision of SFAS 123. SFAS 123R requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award the requisite service period (usually the vesting period). Since January 1, 2004 Pengrowth has recognized the costs of equity instruments issued in exchange for employee services based on the grant-date fair value of the award (Note 2), in accordance with Canadian GAAP. The methodology for determining fair value of equity instruments issued in exchange for employee services prescribed by SFAS 123R differs from that prescribed by Canadian GAAP. SFAS 123R is effective for exchanges in equity instruments in exchanges for goods or services occurring in fiscal years beginning after June 15, 2005. Adopting the provisions of SFAS 123R is not expected to have a material impact on the U.S. GAAP financial statements.

In May 2005 FASB issued SFAS 154 which deals with the accounting for all voluntary changes in accounting principles as well as changes required by accounting pronouncements that do not include specific transition provisions. SFAS 154 requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. This Statement defines retrospective application as the application of a different accounting principle to prior accounting periods as if that principle had always been used or as the adjustment of previously issued financial statements to reflect a change in the reporting entity. This Statement also redefines restatement as the revising of previously issued financial statements to reflect the correction of an error. SFAS 123R is effective for changes in accounting pronouncements effective in fiscal years beginning after December 15, 2005. Adopting SFAS 154 is not expected to have a material impact on the U.S. GAAP financial statements.

Consolidated Statements of Income

The application of U.S. GAAP would have the following effect on net income as reported:

Stated in thousands of Canadian Dollars, except per trust unit amounts

Years ended December 31,	2005	2004
Net income for the year, as reported	$ 326,326	$ 153,745
Adjustments:		
Depletion and depreciation (a)	24,723	26,000
Unrealized gain (loss) on ineffective portion of oil and natural gas hedges (e)	(255)	300
Realized loss on foreign exchange contract (e)	(2,204)	
Net income U.S. GAAP	$ 348,590	$ 180,045
Other comprehensive income:		
Realized gain on foreign exchange swap (d)(e)		(2,169)
Unrealized hedging gain (loss) (d)(e)	(25,470)	21,186
Comprehensive income U.S. GAAP	$ 323,120	$ 199,062
Net income U.S. GAAP		
Basic	$ 2.22	$ 1.35
Diluted	$ 2.21	$ 1.34

Consolidated Balance Sheets

The application of U.S. GAAP would have the following effect on the Balance Sheets as reported:
Stated in thousands of Canadian Dollars

December 31, 2005	As Reported	Increase (Decrease)	U.S. GAAP
Assets:			
Capital assets (a)	2,067,988	(192,219)	1,875,769
		$ (192,219)	
Liabilities			
Accounts payable	$ 111,493	$ 255	$ 111,748
Current portion of unrealized hedging loss (e)		18,153	18,153
Current portion of unrealized foreign currency contract (e)		2,204	2,204
Unitholders equity (f):			
Accumulated other comprehensive income (d)(e)	$	$ (18,153)	$ (18,153)
Trust Unitholders Equity (a)	1,475,996	(194,678)	1,281,318
		$ (192,219)	

December 31, 2004	As Reported	Increase (Decrease)	U.S. GAAP
Assets:			
Current portion of unrealized hedging gain (e)	$	$ 7,317	$ 7,317
Capital assets (a)	1,989,288	(216,942)	1,772,346
		$ (209,625)	
Unitholders equity (f):			
Accumulated other comprehensive income (d)(e)	$	$ 7,317	$ 7,317
Trust Unitholders Equity (a)	1,462,211	(216,942)	1,245,269
		$ (209,625)	

Additional disclosures required under U.S. GAAP

The components of accounts receivable are as follows:

	As at December 31, 2005	2004
Trade	$ 103,619	$ 77,778
Prepaids	20,230	15,378
Other	3,545	11,072
	$ 127,394	$ 104,228

The components of accounts payable and accrued liabilities are as follows:

	As at December 31, 2005	2004
Accounts payable	$ 50,756	$ 37,588
Accrued liabilities	60,737	42,835
	$ 111,493	$ 80,423