PEYTO

Energy Trust

2

Interim Report
for the six months ended June 30, 2005

Highlights

	3 Months Ended June 30		%	6 Months Ended June 30		%
	2005	2004	Change	**2005**	2004	Change
Operations						
Production						
Natural gas (mcf/d)	**106,866**	87,753	*22%*	**104,965**	82,743	*27%*
Oil & NGLs (bbl/d)	**4,653**	3,918	*19%*	**4,495**	3,598	*25%*
Barrels of oil equivalent (boe/d @ 6:1)	**22,464**	18,544	*21%*	**21,990**	17,389	*26%*
Product prices						
Natural gas ($/mcf)	**8.00**	7.32	*9%*	**7.91**	7.46	*6%*
Oil & NGLs ($/bbl)	**51.03**	40.06	*27%*	**53.18**	39.85	*33%*
Operating expenses ($/boe)	**1.30**	1.04	*25%*	**1.26**	1.06	*19%*
Transportation ($/boe)	**0.68**	0.74	*-8%*	**0.68**	0.66	*3%*
Field netback ($/boe)	**33.97**	30.14	*13%*	**34.71**	31.16	*11%*
General & administrative expenses ($/boe)	**0.10**	0.30	*-67%*	**0.08**	0.23	*-65%*
Interest expense ($/boe)	**1.25**	0.99	*26%*	**1.11**	0.98	*13%*
Financial ($000, except per unit)						
Revenue	**99,427**	72,757	*37%*	**193,496**	138,508	*40%*
Royalties (net of ARTC)	**25,954**	18,904	*37%*	**47,626**	34,457	*38%*
Funds from operations	**66,548**	48,548	*37%*	**133,184**	94,560	*41%*
Funds from operations per unit*	**0.69**	0.53	*30%*	**1.38**	1.04	*33%*
Cash distributions	**33,898**	23,320	*45%*	**64,370**	43,896	*47%*
Cash distributions per unit*	**0.35**	0.255	*37%*	**0.665**	0.48	*39%*
Percentage of funds from operations distributed	**51**	48	*6%*	**48**	46	*4%*
Earnings	**25,690**	30,347	*-15%*	**63,121**	54,690	*15%*
Earnings per diluted unit*	**0.27**	0.33	*-18%*	**0.65**	0.60	*8%*
Capital expenditures	**58,730**	37,067	*58%*	**157,805**	98,255	*61%*
Weighted average trust units outstanding*	**96,848,988**	91,450,544	*6%*	**96,757,110**	91,446,916	*6%*
As at June 30						
Net debt (before future compensation expense)				**304,165**	210,057	*45%*
Unitholders' equity				**212,395**	128,755	*65%*
Total assets				**726,064**	472,528	*54%*

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

Report from the president

Peyto Energy Trust ("Peyto") is a leader in the exploration and development of natural gas in western Canada. Our core areas are located in Alberta's premier gas exploration area, the Deep Basin. The combination of our solid foundation and our ability to profitably find and develop oil and natural gas reserves makes Peyto a unique energy trust. We are proud to present our operating and financial results for the second quarter of the 2005 fiscal year.

The following summarizes the Trust's foundation.

- Long reserve life - Proved 12.2 years, Proved Plus Probable 17.2 years at the beginning of 2005
- Low operating costs - $1.30/boe, second quarter 2005
- Low base general and administrative costs - $0.10/boe, second quarter 2005
- High netback – $32.56/boe, second quarter 2005
- High operatorship - 97% of production
- Low cash distribution payout ratio - 51% of second quarter 2005 funds from operations
- Low debt to funds from operations ratio - 1.14 (net debt, before provision for future compensation, divided by annualized second quarter 2005 funds from operations)
- Since inception, Peyto has raised a total of $173.8 million issuing units from treasury, accumulated earnings of $237.5 million, and distributed $198.9 million to unitholders
- Transparent capital structure - no convertible debentures, no exchangeable shares, no stock options, no warrants

In spite of an unusually wet spring in our area of operations, production grew 4% from the first quarter of the year. This represents our 22nd consecutive period of quarterly production growth from 110 boe/d in the fourth quarter of 1999 to 22,464 boe/d in this quarter. What makes this achievement unique is how profitably we have been able to find and develop such high quality reserves relying solely on the expertise of our technical team. The following summarizes performance highlights for the second quarter of 2005.

- Production growth - production increased 21% from 18,544 boe/d in 2004 to 22,464 boe/d in the second quarter of 2005
- Per unit production growth - increased 19% per trust unit after adjusting for debt and bonuses
- Per unit funds from operations growth - increased 30% in the second quarter of 2005 compared to the second quarter of 2004
- Capital expenditures – $59 million was spent to find and develop new natural gas reserves
- Cash distributions per unit increased by 37% from the second quarter of 2004 while the payout ratio remained a low 51%. A total of $34 million or $0.35 per unit was distributed to unitholders in the second quarter of 2005.
- Trust units split 2 for 1 on May 31, 2005.

Funds from operations

Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before bonuses, non-cash and non-recurring expenses. We believe that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.

	3 Months Ended June 30		6 Months Ended June 30	
	2005	2004	**2005**	2004
Earnings	**25,690**	30,347	**63,121**	54,690
Items not requiring cash:				
Provision for bonuses	**21,118**	3,087	**25,045**	11,611
Future income tax expense	**5,261**	4,812	**17,730**	9,929
Depletion, depreciation and accretion	**14,479**	10,302	**27,288**	18,330
Funds from operations	**66,548**	48,548	**133,184**	94,560

Quarterly Review

In the second quarter, we invested $58.7 million, into finding and developing new gas reserves in our core areas. Costs associated with drilling and completing new reserves accounted for $46.4 million of the total, while pipeline and facility construction accounted for $7.9 million. Completion and tie-in activity was curtailed by an unusually long period of wet conditions while our drilling activity was focused on more accessible areas. Peyto drilled 20 gross (16.4 net) wells in the second quarter 2005 and brought 19.9 net zones on production.

Operating costs averaged $1.30 per boe. Our cost structure continues to be one of the lowest and most stable in the North American energy sector. Over the past five years we have managed to keep our operating costs flat while we have increased our production 12 fold. Commodity prices were very strong during the quarter averaging $8.00 per mcf of natural gas and $51.03 per barrel of oil and natural gas liquids. The liquids price was lower than the previous quarter due to higher trucking costs associated with the unusually wet weather and a reduction in the premium for condensate realized in the first quarter.

Activity Update

To date in 2005, Peyto has drilled 68 gross (57.5 net) wells making this the most active drilling year in our six year history. We currently have 8 rigs active in core areas and anticipate that this level of activity will continue throughout the balance of the year. After a period of curtailed tie-in activity, our current production has stabilized at 22,500 boe/d. Surface conditions have now improved and will allow us to access more than 65 net zones that have been drilled and are awaiting tie-in. By year end, Peyto's 2005 capital program will have proven up approximately 150 net zones, with the majority of them on production. In some new areas where we own no infrastructure, limits on surface access and third party processing capacity has resulted in delays bringing wells on production. The majority of these delays are expected to be resolved by year end.

Peyto has committed to the forward sale of 543,900 barrels of crude oil at an average price of $61.51 per barrel and 29,690,000 gigajoules (GJ) of natural gas at an average price of $7.65 per GJ. This hedged volume represents 5% of the total proven reserves that were assigned at the beginning of the year. Based on the historical heating value of Peyto's natural gas, the price per mcf on the forward sale will be $8.95, 12% higher than the price realized in the second quarter of 2005.

Outlook

Our technical team has successfully expanded the quantity of our internally generated investments without compromising the quality. Capital expenditures for 2005 continue to be on a record pace and are forecast to be between $260 million and $300 million. As with previous years, the majority of our capital program will involve drilling, completion and tie-in of lower risk development gas wells adjacent to existing infrastructure in Peyto's core areas. These expenditures will be funded with a combination of funds from operations, working capital, equity and bank lines.

Our performance combined with the foundation we have built clearly indicates that our business strategy works. If you are interested in learning more about our business and willing to invest some of your time to understand Peyto's past and future, we suggest that you visit the Peyto website at www.peyto.com where you will find a current presentation, financial and historical news releases and an updated insider trading summary.

Don T. Gray
President and Chief Executive Officer
August 10, 2005

Management’s discussion and analysis

This Management's Discussion and Analysis (“MD&A”) should be read in conjunction with the unaudited interim consolidated financial statements for the period ended June 30, 2005 and the audited consolidated financial statements of Peyto Energy Trust (“Peyto”) for the year ended December 31, 2004. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”).

The Trust was created by way of a Plan of Arrangement effective July 1, 2003 which reorganized Peyto Exploration & Development Corp. (“PEDC”) from a corporate entity into a trust. Accordingly, the consolidated financial statements were reported on a continuity of interests basis. As such, comparative figures for the periods prior to July 1, 2003 are the financial results of PEDC. This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of August 9, 2005. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com.

Certain information set forth in this Management’s Discussion and Analysis, including management's assessment of the Trust's future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond these parties' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Peyto's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Peyto will derive therefrom. Peyto disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before bonuses, non-cash and non-recurring expenses. We believe that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.

All references are to Canadian dollars unless otherwise indicated. Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

Recently, proposed new legislation to restrict foreign ownership was issued in draft form by the Department of Finance and has prompted all trusts, including Peyto, to review their capital structures. To the best of our knowledge, Peyto's foreign ownership level currently stands at approximately 21.5 percent, well below the level that would jeopardize Peyto's status as a mutual fund trust under this proposed legislation. A few trusts have reorganized, or propose to reorganize, their units into a dual class structure with the objective of restricting foreign ownership to less than 50 percent and therefore retaining their status as a mutual fund trust. Peyto is an active supporter of the efforts of the Canadian Association of Income Funds (CAIF) which is attempting to have the Department of Finance reconsider components of the proposed legislation. The Department of Finance has subsequently announced that they are taking more time to consider the proposed legislation. The Trust will continue to monitor these developments and if it is deemed appropriate, propose an amendment to its capital structure.

OVERVIEW

Peyto is a Canadian energy trust involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2004, we had total proved plus probable reserves of 129.5 million barrels of oil equivalent with a reserve life of 17.2 years as evaluated by our independent petroleum engineers. Our production is weighted as to approximately 80% natural gas and 20% natural gas liquids and oil.

The Peyto model is designed to deliver growth in its assets, production and income, all on a per unit basis. The model is built around three key principles:

- Using our technical expertise to achieve the best return on capital employed, through the development of internally generated drilling projects.
- A low payout ratio designed to efficiently fund our growing inventory of drilling projects.
- Having an asset base which is made up of high quality long life natural gas reserves.

Operating results over the last six years indicate that we have successfully implemented these principles. Our business model makes Peyto a truly unique energy trust.

QUARTERLY FINANCIAL INFORMATION

	2005	2004					2003	
($000 except per unit amounts)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Total revenue (net of royalties)	**73,473**	72,397	66,024	59,337	53,853	50,197	45,901	40,743
Funds from operations	**66,548**	66,636	60,334	54,211	48,548	46,012	41,371	35,882
Per unit – basic*	**0.69**	0.69	0.65	0.60	0.53	0.51	0.46	0.40
Per unit – diluted*	**0.69**	0.69	0.65	0.60	0.53	0.51	0.46	0.40
Earnings (loss)	**25,690**	37,431	(2,558)	21,650	30,347	24,343	6,203	25,445
Per unit – basic*	**0.27**	0.39	(0.03)	0.24	0.33	0.27	0.07	0.28
Per unit – diluted*	**0.27**	0.39	(0.03)	0.24	0.33	0.27	0.07	0.28

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

RESULTS OF OPERATIONS

Production

	Three Months ended June 30		Six Months ended June 30	
	2005	2004	**2005**	2004
Natural gas (mmcf/d)	**106.9**	87.8	**104.9**	82.7
Oil & natural gas liquids (bbl/d)	**4,653**	3,918	**4,495**	3,598
Barrels of oil equivalent (boe/d)	**22,464**	18,544	**21,990**	17,389

Natural gas production averaged 106.9 mmcf/d in the second quarter of 2005, 22 percent higher than the 87.8 mmcf/d reported for the same period in 2004. Oil and natural gas liquids production averaged 4,653 bbl/d, an increase of 19 percent from 3,918 bbl/d reported in the prior year. First half production increased 26 percent from 17,389 boe/d to 21,990 boe/d. The production increases are directly attributable to Peyto's ongoing drilling program.

Commodity Prices

	Three Months ended June 30		Six Months ended June 30	
	2005	2004	**2005**	2004
Natural gas ($/mcf)	**8.11**	7.70	**7.86**	7.38
Hedging – gas ($/mcf)	**(0.11)**	(0.38)	**0.05**	0.08
Natural gas – after hedging ($/mcf)	**8.00**	7.32	**7.91**	7.46
Oil and natural gas liquids($/bbl)	**54.88**	42.84	**56.29**	41.48
Hedging – oil ($/bbl)	**(3.85)**	(2.77)	**(3.11)**	(1.63)
Oil and natural gas liquids – after hedging ($/bbl)	**51.03**	40.06	**53.18**	39.85
Total Hedging ($/boe)	**(1.33)**	(2.36)	**(0.41)**	0.07

Our natural gas price before hedging averaged $8.11/mcf during the second quarter of 2005, an increase of 5 percent from $7.70/mcf reported for the equivalent period in 2004. Oil and natural gas liquids prices averaged $54.88/bbl up 28 percent from $42.84/bbl a year earlier. Hedging activity for the second quarter of 2005 reduced Peyto's price achieved by $1.33/boe. Expectations are for commodity prices to remain strong relative to historical pricing.

Revenue

	Three Months ended June 30		Six Months ended June 30	
($000)	**2005**	2004	**2005**	2004
Natural gas	**78,909**	61,466	**149,330**	111,108
Oil and natural gas liquids	**23,236**	15,274	**45,803**	27,166
Hedging gain (loss)	**(2,718)**	(3,983)	**(1,637)**	234
Total revenue	**99,427**	72,757	**193,496**	138,508

For the three months ended June 30, 2005, gross revenue increased 37 percent to $99.4 million from $72.8 million for the same period in 2004. The increase in revenue for the period was a result of increased production volumes and pricing as detailed in the following table:

	Three Months ended June 30				Six Months ended June 30			
	2005	2004	Change	**$million**	2005	2004	Change	**$million**
Natural gas								
Volume (mcf/d)	106,866	87,753	19,113		104,965	82,743	22,222	
Volume (mmcf)	9,724.8	7,985.5	1,739.3	**12.7**	18,998.7	15,059.3	3,939.4	**29.4**
Price ($/mcf)	$8.00	$7.32	$0.68	**6.6**	$7.91	$7.46	$0.45	**8.4**
Oil & NGL								
Volume (bbl/d)	4,653	3,918	735		4,496	3,598	897	
Volume (mbbl)	423.4	356.6	66.8	**2.7**	813.7	654.9	158.8	**6.3**
Price ($/bbl)	$51.03	$40.06	$10.97	**4.6**	$53.18	$39.85	$13.33	**10.8**
Total revenue ($million)	99.4	72.8	26.6	**26.6**	193.4	138.5	54.9	**54.9**

Royalties

We pay royalties to the owners of the mineral rights with whom we hold leases, including the provincial government of Alberta. Alberta gas crown royalties are invoiced on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances.

	Three Months ended June 30		Six Months ended June 30	
	2005	2004	**2005**	2004
Royalties, net of ARTC ($000)	**25,954**	18,904	**47,626**	34,457
% of sales	**26**	26	**25**	25
$/boe	**12.69**	11.20	**11.19**	10.89

For the second quarter of 2005, royalties averaged $12.69/boe or approximately 26 percent of Peyto's total petroleum and natural gas sales. The royalty rate expressed as a percentage of sales, will fluctuate from period to period due to the fact that the Alberta Reference Price can differ significantly from the commodity prices obtained by the Trust.

Operating Costs & Transportation

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party gas reduces operating expenses.

	Three Months ended June 30		Six Months ended June 30	
	2005	2004	**2005**	2004
Operating costs ($000)				
Field expenses	**4,235**	3,111	**8,061**	5,811
Processing and gathering income	**(1,583)**	(1,363)	**(3,045)**	(2,469)
Total operating costs	**2,652**	1,748	**5,016**	3,342
$/boe	**1.30**	1.04	**1.26**	1.06
Transportation	**1,387**	1,249	**2,703**	2,103
$/boe	**0.68**	0.74	**0.68**	0.66

Operating costs were $2.6 million in the second quarter compared to $1.7 million during the same period a year earlier. On a unit-of-production basis, operating costs averaged $1.30/boe in the second quarter of 2005 compared to $1.04/boe for the second quarter of 2004.

Netbacks

Operating netbacks represent the profit margin associated with the production and sale of petroleum and natural gas. The primary factors that produce Peyto's strong netbacks are a low cost structure and the high heat content of our natural gas that results in higher commodity prices.

	Three Months ended June 30		Six Months ended June 30	
($/boe)	**2005**	2004	**2005**	2004
Sale Price	**48.64**	43.12	**47.84**	43.77
Less:				
Royalties	**12.69**	11.20	**11.97**	10.89
Operating costs	**1.30**	1.04	**1.26**	1.06
Transportation	**0.68**	0.74	**0.68**	0.66
Operating netback	**33.97**	30.14	**34.71**	31.16
General and administrative	**0.10**	0.30	**0.08**	0.23
Interest on long-term debt	**1.25**	0.99	**1.11**	0.98
Capital tax	**0.06**	0.08	**0.06**	0.07
Cash netback	**32.56**	28.77	**33.46**	29.88

General and Administrative Expenses

	Three Months ended June 30		Six Months ended June 30	
	2005	2004	**2005**	2004
G&A expenses ($000)	**1,529**	1,146	**2,940**	2,094
Overhead recoveries	**(1,320)**	(640)	**(2,620)**	(1,382)
Net G&A expenses	**209**	506	**320**	712
$/boe	**0.10**	0.30	**0.08**	0.23

General and administrative expenses before overhead recoveries increased to $1.5 million in the second quarter of 2005, as compared to $1.1 million for the same period in 2004 primarily due to staffing increases required to manage our active drilling program and increasing property base. Net of overhead recoveries associated with our capital expenditures program, general and administrative costs decreased to $0.10 per boe from $0.30 per boe in 2004.

Interest Expense

	Three Months ended June 30		Six Months ended June 30	
	2005	2004	**2005**	2004
Interest expense ($000)	**2,552**	1,671	**4,422**	3,108
$/boe	**1.25**	0.99	**1.11**	0.98

Second quarter 2005 interest expense was $2.5 million or $1.25/boe compared to $1.7 million or $0.99/boe a year earlier. During 2005, average debt levels have increased to partially fund Peyto's capital expenditures program. Interest rates continue to be favourable and are not expected to increase substantially in the short-term.

Depletion, Depreciation and Accretion

The second quarter 2005 provision for depletion, depreciation and accretion totaled $14.5 million as compared to $10.3 million for the same period in 2004. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $7.08/boe as compared to $5.80/boe in 2004. Increases or decreases in the depletion rate on a unit-of-production basis are influenced by the reserves added through Peyto's drilling program.

Income Taxes

The current provision for future income tax increased to $17.7 million for the first half of 2005 from $9.9 million in 2004. The change is primarily due to increased profitability resulting from higher production volumes and commodity prices.

HEDGING

Commodity Price Risk Management

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these contracts with well established counter-parties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. During the first half of 2005, we recorded a hedging loss of $1.6 million as compared to a hedging gain $0.2 million in the first half of 2004. A summary of contracts outstanding in respect of the hedging activities are as follows:

Crude Oil Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
July 1 to September 30, 2005	Fixed price	250 bbl	$54.08/bbl
July 1 to September 30, 2005	Fixed price	350 bbl	$56.08/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$59.02/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$53.12/bbl
July 1 to September 30, 2005	Fixed price	100 bbl	$54.35/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$62.22/bbl
October 1 to December 31, 2005	Fixed price	300 bbl	$54.35/bbl
October 1 to December 31, 2005	Fixed price	250 bbl	$57.52/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$52.07/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$53.15/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$55.20/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$60.50/bbl
January 1 to March 31, 2006	Fixed price	300 bbl	$53.85/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$54.58/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$57.65/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$58.90/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$65.21/bbl
January 1 to March 31, 2006	Fixed price	100 bbl	$69.40/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$64.75/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$64.62/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$68.64/bbl
April 1 to June 30, 2006	Fixed price	300 bbl	$76.00/bbl

July 1 to September 30, 2006	Fixed price	200 bbl	$70.00/bbl
July 1 to September 30, 2006	Fixed price	200 bbl	$72.15/bbl
July 1 to September 30, 2006	Fixed price	300 bbl	$75.40/bbl
October 1 to December 31, 2006	Fixed price	200 bbl	$69.40/bbl
October 1 to December 31, 2006	Fixed price	200 bbl	$71.10/bbl

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.71/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.45/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.55/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.00/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.27/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.42/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.65/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.90/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.01/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.11/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.40/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.50/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.60/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.70/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.80/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.91/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.01/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.15/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.22/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.32/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.50/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.72/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.55/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$9.00/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$9.75/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.10/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.20/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.30/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.35/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.45/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.61/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.75/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$8.71/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.00/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.05/GJ

Commodity Price Sensitivity

Our low operating costs, low distribution ratio and long reserve life reduce our sensitivity to changes in commodity prices.

Currency Risk Management

The Trust is exposed to fluctuations in the Canadian/US dollar exchange ratio since our natural gas and oil sales are effectively priced in US dollars and converted to Canadian dollars. Currently we have not entered into any agreements to manage this specific risk.

Interest Rate Risk Management

The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently we have not entered into any agreements to manage this risk. At June 30, 2005, the increase or decrease in earnings for each 100 bps change in interest rate paid on the outstanding revolving demand loan amounts to approximately $2.3 million per annum.

LIQUIDITY AND CAPITAL RESOURCES

Funds from Operations

	Three Months ended June 30		Six Months ended June 30	
($000)	**2005**	2004	**2005**	2004
Earnings	**25,690**	30,347	**63,121**	54,690
Items not requiring cash:				
Provision for bonuses	**21,118**	3,087	**25,045**	11,611
Future income tax expense	**5,261**	4,812	**17,730**	9,929
Depletion, depreciation & accretion	**14,479**	10,302	**27,288**	18,330
Funds from operations	**66,548**	48,548	**133,184**	94,560

For the quarter ended June 30, 2005, funds from operations totaled $66.5 million or $0.69 per unit, representing a 37 percent increase from the $48.5 million, or $0.53 per unit during the same period in 2004. Peyto's policy is to distribute approximately 50% of funds from operations to unitholders while retaining the balance to fund its growth oriented capital expenditures program. Our earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond our control. Current volatility in commodity prices creates uncertainty as to our funds from operations and capital expenditure budget. Accordingly, we assess results throughout the year and revise our operational plans as necessary to reflect the most current information.

Our revenues will be impacted by drilling success and production volumes as well as external factors such as the market prices for natural gas and crude oil and the exchange rate of the Canadian dollar relative to the US dollar.

Bank Debt

We have an extendible revolving term credit facility with a syndicate of financial institutions in the amount of $350 million including a $330 million revolving facility and a $20 million operating facility. Available borrowings are limited by a borrowing base, which is based on the value of petroleum and natural gas assets as determined by the lenders. The loan is reviewed annually and may be extended at the option of the lender for an additional 364 day period. If not extended, the revolving facility will automatically convert to a one year and one day non-revolving term loan. The loan has therefore been classified as long-term on the balance sheet.

At June 30, 2005, $280 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At June 30, 2005, we had a working capital deficit of $65.4 million.

We believe that funds generated from our operations, together with borrowings under our credit facility and proceeds, if any, from equity issued will be sufficient to finance our current operations and planned capital expenditure program. We anticipate that our 2005 capital expenditures will be between $260 and $300 million. In 2005, almost all of Peyto's capital expenditures are discretionary focused on exploration, development and acquisition activity. The majority of these expenditures will be employed to drill, complete and tie-in natural gas wells adjacent to Peyto's existing infrastructure. Peyto has the flexibility to match planned capital expenditures to actual cash flow.

Capital

At August 9, 2005, 96,923,916 trust units were outstanding (June 30, 2005 - 96,888,404). On May 31, 2005, Peyto trust units split 2 for 1.

Peyto implemented a Distribution Reinvestment Plan ("DRIP") effective with the March 2005 distribution whereby eligible unitholders may elect to reinvest their monthly cash distributions in additional trust units at a 5% discount to market price. On July 15, 2005 35,512 trust units were issued at a price of $28.14 per trust unit pursuant to the DRIP.

Authorized: Unlimited number of voting trust units
Issued and Outstanding:

Trust Units (no par value)	Number of Shares/Units	Amount $
Balance, December 31, 2004	47,725,272	138,953,026
Trust units issued by private placement	670,000	31,586,375
Trust unit issue costs	-	(103,010)
Trust units issued pursuant to DRIP	28,645	1,356,148
Trust units issued pursuant to 2 for 1 split	48,423,917	-
Trust units issued pursuant to DRIP	40,570	1,009,376
Balance, June 30, 2005	96,888,404	172,801,915

Market & Reserves Based Bonuses

The Trust awards bonuses to employees and key consultants. The bonus structure is comprised of market and reserves based components.

Under the reserves based component, the bonus pool, on an annual basis, will be initially comprised of 3% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%. The independent reserves evaluation for 2005 will be completed in January 2006. A quarterly provision for the reserves based bonus is based on internally estimated proved producing reserves additions using 2005 forecast commodity prices adjusted for changes in debt, equity and distributions. Proved producing reserves are estimated based on year-to-date production growth. This methodology can generate interim results which may vary significantly from the final bonus paid. A provision for compensation expense of $479,000 was recorded for the first half of 2005.

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 7% of the total number of trust units outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. The bonus is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated distributions of a trust unit for that period. A tax factor of 1.333 is then applied to determine the amount of the bonus to be paid.

Based on the five day weighted average trading price of the trust units for the period ended June 30, 2005, compensation costs related to 4.8 million non-vested rights, with an average grant price of $16.69, total $89.4 million. The Trust records a non-cash provision for future compensation expense over the life of the rights. The cumulative provision totals $52.9 million of which $24.6 million was recorded in the first half of 2005.

Capital Expenditures

Net capital expenditures for the second quarter of 2005 totaled $58.7 million. Exploration and development related activity represented $46.4 million or 79% of the total, while expenditures on facilities, gathering systems and equipment totaled $7.9 million or 13% of the total. The following table summarizes capital expenditures for the year.

	Three Months ended June 30		Six Months ended June 30	
($000)	**2005**	2004	**2005**	2004
Land	**2,916**	2,152	**5,292**	2,635
Seismic	**1,507**	382	**2,502**	1,360
Drilling – Exploratory & Development	**46,369**	26,161	**119,896**	61,910
Production Equipment, Facilities & Pipelines	**7,910**	8,213	**30,094**	29,127
Acquisitions & Dispositions	**-**	100	**-**	3,150
Office Equipment	**28**	59	**21**	72
Total capital expenditures	**58,730**	37,067	**157,805**	98,254

Cash Distributions

	Three Months ended June 30		Six Months ended June 30	
	2005	2004	**2005**	2004
Funds from operations ($000)	**66,548**	48,548	**133,184**	94,560
Distributions ($000)	**33,898**	23,320	**64,370**	43,896
Distributions per unit ($)*	**0.35**	0.255	**0.665**	0.48
Payout ratio (%)	**51**	48	**48**	46

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

Peyto's strategy is to distribute approximately 50 percent of funds from operations to our unitholders on a monthly basis with the balance being withheld to fund capital expenditures. Management is prepared to adjust the payout levels to balance desired distributions with our requirement to maintain an appropriate capital structure. For Canadian income tax purposes distributions made are considered a combination of income and return of capital. The portion that is return of capital reduces the adjusted cost base of the units.

Contractual Obligations

The Trust is committed to payments under operating leases for office space as follows:

	$
2005	368,062
2006	953,484
2007	953,484
2008	1,096,641
2009	1,096,641
2010	1,096,641
2011	1,096,641
	6,661,594

GUARANTEES/OFF-BALANCE SHEET ARRANGEMENTS

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts as discussed further in the Hedging section.

INCOME TAXES

The following sets out a general discussion of the Canadian and US tax consequences of holding Peyto units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Unitholders or potential Unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Taxpayers

The Trust qualifies as a mutual fund trust under the *Income Tax Act* (Canada) and, accordingly, Trust units are qualified investments for RRSPs, RRIFs, RESPs and DPSPs. Each year, the Trust is required to file an income tax return and any taxable income of the Trust is allocated to unitholders.

Unitholders are required to include in computing income their pro-rata share of any taxable income earned by the Trust in that year. An investor's adjusted cost base (ACB) in a trust unit equals the purchase price of the unit less any non-taxable cash distributions received from the date of acquisition. To the extent the unitholders' ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholders' ACB will be brought to nil.

During the first half of 2005, the Trust paid distributions to the unitholders in the amount of $64.4 million (2004 - $43.9 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit*
January 2005	January 31, 2005	February 15, 2005	$0.095
February 2005	February 28, 2005	March 15, 2005	$0.11
March 2005	March 31, 2005	April 15, 2005	$0.11
April 2005	April 29, 2005	May 13, 2005	$0.11
May 2005	May 31, 2005	June 15, 2005	$0.12
June 2005	June 30, 2005	July 15, 2005	$0.12

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

US Taxpayers

US unitholders who receive cash distributions are subject to a 15 percent Canadian withholding tax, applied to the taxable portion of the distributions as computed under Canadian tax law. US taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distributions, if any, is determined by the Trust in relation to its current and accumulated earnings and profit using US tax principles. The taxable portion so determined, is considered to be a dividend for US tax purposes.

The non-taxable portion of the cash distributions is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as a gain.

US unitholders are advised to seek legal or tax advice from their professional advisors.

RISK MANAGEMENT

Investors who purchase our units are participating in the net funds from operations from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the funds from operations paid to investors and the value of the units are subject to numerous risks inherent in the oil and natural gas industry.

Our expected funds from operations depends largely on the volume of petroleum and natural gas production and the price received for such production, along with the associated operating costs. The price we receive for our oil depends on a number of factors, including West Texas Intermediate oil prices, Canadian/US currency exchange rates, quality differentials and Edmonton par oil prices. The price we receive for our natural gas production is primarily dependent on current Alberta market prices. Peyto has an ongoing commodity price risk management policy that provides for downside protection on a portion of its future production while allowing access, in certain cases, to the upside price movements.

Although our focus is on our internally generated drilling programs, any acquisition of oil and natural gas assets depends on our assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the units. We employ experienced staff on our team and perform appropriate levels of due diligence on our analysis of acquisition targets, including a detailed examination of reserve reports; if appropriate, re-engineering of reserves for a large portion of the properties to ensure the results are consistent; site examinations of facilities for environmental liabilities; detailed examination of balance sheet accounts; review of contracts; review of prior year tax returns and modeling of the acquisition to attempt to ensure accretive results to the unitholders.

Inherent in development of the existing oil and gas reserves are the risks, among others, of drilling dry holes, encountering production or drilling difficulties or experiencing high decline rates in producing wells. To minimize these risks, we employ experienced staff to evaluate and operate wells and utilize appropriate technology in our operations. In addition, we use prudent work practices and procedures, safety programs and risk management principles, including insurance coverage against potential losses.

The value of our Trust units is based on among other things, the underlying value of the oil and natural gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and gas prices increase the risk of write-downs on our oil and gas property investments. In order to mitigate this risk, our proven and probable oil and gas reserves are evaluated each year by a firm of independent reservoir engineers. The reserves committee of the Board of Directors reviews and approves the reserve report.

Our access to markets may be restricted at times by pipeline or processing capacity. We minimize these risks by controlling as much of our processing and transportation activities as possible and ensuring transportation and processing contracts are in place with reliable cost efficient counter-parties.

The petroleum and natural gas industry is subject to extensive controls, regulatory policies and income and resource taxes imposed by various levels of government. These regulations, controls and taxation policies are amended from time to time. We have no control over the level of government intervention or taxation in the petroleum and natural gas industry. However, we operate in such a manner to ensure that we are in compliance with all applicable regulations and are able to respond to changes as they occur.

The petroleum and natural gas industry is subject to both environmental regulations and an increased environmental awareness. We have reviewed our environmental risks and are, to the best of our knowledge, in compliance with the appropriate environmental legislation and have determined that there is no current material impact on our operations.

We are subject to financial market risk. In order to maintain substantial rates of growth, we must continue reinvesting in, drilling for or acquiring petroleum and natural gas. Our capital expenditure program is funded primarily through funds from operations, debt and when appropriate, through the issuance of equity.

CRITICAL ACCOUNTING ESTIMATES

Reserve Estimates

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent to the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is an analytical process of estimating underground accumulations of oil and natural gas that can be difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future royalties and operating costs, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Trust's oil and natural gas properties and the rate of depletion of the oil and natural gas properties as well as the calculation of the reserves based bonus. Actual production, revenues and expenditures with respect to the Trust's reserves will likely vary from estimates, and such variances may be material.

The Trust's estimated quantities of proved and probable reserves at December 31, 2004 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 6 consecutive years.

Depletion and Depreciation Estimate

We follow the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

All costs of exploring for and developing petroleum and natural gas reserves, together with the costs of production equipment, are depleted and depreciated on the unit-of-production method based on estimated gross proven reserves. Petroleum and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content (6 mcf to 1 barrel of oil).

Costs of acquiring unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The ceiling test is based on estimates of proved reserves, production rates, estimated future petroleum and natural gas prices and costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Asset Retirement Obligation

The asset retirement obligation is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonment and reclamation discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Future Market Based Bonus

The provision for future market based bonus is estimated based on current market conditions, distribution history and on the assumption that all outstanding rights will be paid out according to the vesting schedule. The conditions at the time of vesting could vary significantly from the current conditions and may have a material effect on the calculation.

Reserves Based Bonus

The reserves based bonus is calculated based on the year end independent reserves evaluation which will be completed in January 2006. A quarterly provision for the reserves based bonus is based on estimated proved producing reserves additions adjusted for changes in debt, equity and distributions. Actual proved producing reserves additions and forecasted commodity prices could vary significantly from those estimated and may have a material effect on the calculation.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

CHANGES IN ACCOUNTING POLICIES

None

ADDITIONAL INFORMATION

Additional information relating to Peyto Energy Trust can be found on SEDAR at www.sedar.com and www.peyto.com.

Quarterly information

	2005		2004		
	Q2	Q1	Q4	Q3	Q2
Operations					
Production					
Natural gas (mcf/d)	**106,866**	103,043	97,968	91,782	87,753
Oil & NGLs (bbl/d)	**4,653**	4,337	4,360	3,967	3,918
Barrels of oil equivalent (boe/d @ 6:1)	**22,464**	21,511	20,688	19,264	18,544
Average product prices					
Natural gas ($/mcf)	**8.00**	7.81	7.58	7.00	7.32
Oil & natural gas liquids ($/bbl)	**51.03**	55.52	46.82	43.13	40.06
Average operating expenses ($/boe)	**1.30**	1.22	1.03	1.08	1.04
Average transportation costs ($/boe)	**0.68**	0.68	0.77	0.68	0.74
Field netback ($/boe)	**33.97**	35.50	32.90	31.72	30.14
General & administrative expense ($/boe)	**0.10**	0.06	0.01	0.05	0.30
Interest expense ($/boe)	**1.25**	0.97	1.03	1.03	0.99
Financial ($000 except per unit)					
Revenue	**99,427**	94,069	87,127	74,866	72,757
Royalties (net of ARTC)	**25,954**	21,672	21,103	15,529	18,904
Funds from operations	**66,548**	66,636	60,334	54,211	48,548
Funds from operations per unit*	**0.69**	0.69	0.65	0.60	0.53
Cash distributions	**33,898**	30,472	26,443	23,320	23,320
Cash distributions per unit*	**0.35**	0.315	0.285	0.255	0.255
Percentage of funds from operations distributed	**51%**	46%	44%	43%	48%
Earnings	**25,690**	37,431	(2,558)	21,650	30,347
Earnings per diluted unit*	**0.27**	0.39	(0.03)	0.24	0.33
Capital expenditures	**58,730**	99,074	76,953	55,565	37,067
Weighted average trust units outstanding*	**96,848,988**	96,664,210	92,494,022	91,450,544	91,450,544

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

Peyto Energy Trust

Consolidated Balance Sheets

(unaudited)

	June 30, 2005 $	December 31, 2004 $
Assets		
Current		
Cash	**6,416,561**	-
Accounts receivable	**52,692,058**	58,992,005
Due from private placements	**-**	27,080,066
Prepaid expenses and deposits	**4,562,419**	5,262,778
	63,671,038	91,334,849
Property, plant and equipment *(Notes 2 and 3)*	**662,392,862**	531,241,786
	726,063,900	622,576,635
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**76,836,712**	124,753,199
Capital taxes payable	**371,533**	483,081
Cash distributions payable	**10,627,311**	9,067,811
Provision for future market and reserves based bonus	**41,205,841**	22,298,937
	129,041,397	156,603,028
Long-term debt *(Note 3)*	**280,000,000**	180,000,000
Provision for future market based bonus	**12,258,916**	6,121,097
Asset retirement obligations	**3,963,600**	3,328,834
Future income taxes	**88,404,993**	70,675,002
	384,627,509	260,124,933
Unitholders' equity		
Unitholders' capital *(Note 4)*	**172,801,915**	138,953,026
Units to be issued *(Note 4)*	**999,298**	27,052,850
Accumulated earnings	**237,479,025**	174,358,093
Accumulated cash distributions *(Note 5)*	**(198,885,244)**	(134,515,295)
	212,394,994	205,848,674
	726,063,900	622,576,635

See accompanying notes

On behalf of the Board:

(signed) *"Michael MacBean"*
Director

(signed) *"Donald T. Gray"*
Director

Peyto Energy Trust

Consolidated Statements of Earnings and Accumulated Earnings

(unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
	$	$	**$**	$
Revenue				
Petroleum and natural gas sales, net	**73,472,840**	53,853,189	**145,869,788**	104,050,585
Expenses				
Operating *(Note 6)*	**2,652,209**	1,747,800	**5,015,582**	3,341,903
Transportation	**1,386,829**	1,248,879	**2,702,996**	2,102,775
General and administrative	**209,031**	506,276	**319,674**	711,828
Future market and reserves based bonus provision	**21,117,684**	3,086,691	**25,044,723**	11,611,492
Interest	**2,551,745**	1,671,280	**4,422,402**	3,107,813
Depletion, depreciation and accretion *(Note 2)*	**14,479,191**	10,302,078	**27,288,487**	18,329,732
	42,396,689	18,563,004	**64,793,864**	39,205,543
Earnings before taxes	**31,076,151**	35,290,185	**81,075,924**	64,845,042
Taxes				
Future income tax expense	**5,260,992**	4,812,443	**17,729,992**	9,928,707
Capital tax expense	**125,000**	130,532	**225,000**	226,018
	5,385,992	4,942,975	**17,954,992**	10,154,725
Net earnings for the period	**25,690,159**	30,347,210	**63,120,932**	54,690,317
Accumulated earnings, beginning of period	**211,788,866**	124,919,566	**174,358,093**	100,576,459
Accumulated earnings, end of period	**237,479,025**	155,266,776	**237,479,025**	155,266,776
Earnings per unit *(Note 4)*				
Basic	**0.27**	0.33	**0.65**	0.60
Diluted	**0.27**	0.33	**0.65**	0.60

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Cash Flows

(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
	$	$	**$**	$
Cash provided by (used in)				
Operating Activities				
Net earnings for the period	**25,690,159**	30,347,210	**63,120,932**	54,690,317
Items not requiring cash:				
Future income tax expense	**5,260,992**	4,812,443	**17,729,992**	9,928,707
Depletion, depreciation and accretion	**14,479,191**	10,302,078	**27,288,487**	18,329,732
Change in non-cash working capital related to operating activities	**10,854,377**	8,850,032	**1,153,941**	6,004,491
	56,284,719	54,311,763	**109,293,352**	88,953,247
Financing Activities				
Issue of trust units, net of costs	**2,874,617**	-	**7,795,337**	-
Distribution payments	**(33,897,533)**	(23,319,918)	**(64,369,949)**	(43,896,330)
Increase in bank debt	**70,000,000**	20,000,000	**100,000,000**	30,000,000
Change in non-cash working capital related to financing activities	**470,546**	914,505	**28,639,566**	9,977,133
	39,447,630	(2,405,413)	**72,064,954**	(3,919,197)
Investing Activities				
Additions to property, plant and equipment	**(58,730,387)**	(37,067,232)	**(157,804,797)**	(98,254,635)
Change in non-cash working capital related to investing activities	**(30,585,401)**	(32,788,210)	**(17,136,948)**	(7,370,633)
	(89,315,788)	(69,855,442)	**(174,941,745)**	(105,625,268)
Net increase (decrease) in cash	**6,416,561**	(17,949,092)	**6,416,561**	(20,591,218)
Cash, beginning of period	**-**	17,949,092	**-**	20,591,218
Cash, end of period	**6,416,561**	-	**6,416,561**	-

Supplemental cash flow information – Note 8
See accompanying notes

Peyto Energy Trust

Notes to Consolidated Financial Statements

June 30, 2005 and 2004

1. Summary of Significant Accounting Policies

The unaudited interim consolidated financial statements of Peyto Energy Trust (the "Trust") follow the same accounting policies as the most recent annual audited financial statements. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles applicable for annual financial statements. Accordingly, these interim financial statements should be read in conjunction with the 2004 audited consolidated financial statements.

These financial statements include the accounts of Peyto Energy Trust and its wholly owned subsidiaries, Peyto Exploration & Development Corp. and Peyto Operating Trust.

Measurement uncertainty

The amount recorded for depletion and depreciation of property, plant and equipment, the asset retirement obligation, the ceiling test calculation and reserve based bonus are based on estimates of gross proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

2. Property, Plant and Equipment

	June 30, 2005	December 31, 2004
	$	$
Property, plant and equipment	**774,738,069**	616,422,327
Accumulated depletion and depreciation	**(112,345,207)**	(85,180,541)
	662,392,862	531,241,786

At June 30, 2005 costs of $28,663,020 (December 31, 2004 - $28,663,020) related to undeveloped land have been excluded from the depletion and depreciation calculation.

3. Long-Term Debt

The Trust has a syndicated $350 million extendible revolving credit facility. The facility is made up of a $20 million working capital sub-tranche and a $330 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of the Trust, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a one year term, at the end of which time the facility would be due and payable. Outstanding amounts on this facility bear interest at rates determined by the Trust's debt to cash flow ratio that range from prime to prime plus 0.75% for debt to cash flow ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank.

4. Unitholders' Capital

Authorized: Unlimited number of voting trust units

Issued and Outstanding

Trust Units	Number of Shares/Units	Amount $
Balance, December 31, 2004	47,725,272	138,953,026
Trust units issued by private placement	670,000	31,586,375
Trust unit issue costs	-	(103,010)
Trust units issued pursuant to DRIP	28,645	1,356,148
Trust units issued pursuant to 2 for 1 split	48,423,917	-
Trust units issued pursuant to DRIP	40,570	1,009,376
Balance, June 30, 2005	**96,888,404**	**172,801,915**

Units to be Issued

The Trust implemented a Distribution Reinvestment Plan ("DRIP") effective for the March 2005 distribution. The DRIP provides eligible holders of trust units of Peyto the opportunity to accumulate additional trust units by reinvesting their cash distributions paid by Peyto. The cash distributions are reinvested at the discretion of Peyto, either by acquiring trust units issued from treasury at a 5% discount to the average market price or by acquiring trust units at prevailing market rates. On July 15, 2005, 35,512 trust units were issued from treasury at a price of $28.14 per trust unit pursuant to the Plan.

Per Unit Amounts

Earnings per unit have been calculated based upon the weighted average number of units outstanding during the period of 96,848,988 (2004 – 91,450,544; restated for 2 for 1 split of trust units May 31, 2005). There are no dilutive instruments outstanding.

5. Accumulated Cash Distributions

Peyto's strategy is to distribute approximately 50 percent of funds from operations to our unitholders on a monthly basis with the balance being withheld to fund capital expenditures. Management is prepared to adjust the payout levels to balance desired distributions with our requirement to maintain an appropriate capital structure. During the six-month period ended June 30, 2005, the Trust paid distributions to the unitholders in the aggregate amount of $64.4 million (2004 - $43.9 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit*
January 2005	January 31, 2005	February 15, 2005	$0.095
February 2005	February 28, 2005	March 13, 2005	$0.11
March 2005	March 31, 2005	April 15, 2005	$0.11
April 2005	April 29, 2005	May 15, 2005	$0.11
May 2005	May 31, 2005	June 15, 2005	$0.12
June 2005	June 30, 2005	July 15, 2005	$0.12

*Note: prior period restated for 2 for 1 split of trust units completed May 31, 2005.

6. Operating Expenses

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party natural gas reduces operating expenses.

	Three Months Ended June 30		**Six Months Ended June 30**	
	2005 $	2004 $	**2005 $**	2004 $
Field expenses	**4,235,214**	3,110,787	**8,060,981**	5,811,078
Processing and gathering income	**(1,583,005)**	(1,362,987)	**(3,045,399)**	(2,469,175)
Total operating costs	**2,652,209**	1,747,800	**5,015,582**	3,341,903

7. Financial Instruments

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these contracts with well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of petroleum and natural gas prices. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Trust's firm commitment or forecasted transaction and the underlying basis of the instrument correlates highly with the Trust's exposure. A summary of contracts outstanding in respect of the hedging activities at June 30, 2005 is as follows:

Crude Oil Period Hedged	Type	Daily Volume	Price (CAD)
July 1 to September 30, 2005	Fixed price	250 bbl	$54.08/bbl
July 1 to September 30, 2005	Fixed price	350 bbl	$56.08/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$59.02/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$53.12/bbl
July 1 to September 30, 2005	Fixed price	100 bbl	$54.35/bbl
July 1 to September 30, 2005	Fixed price	200 bbl	$62.22/bbl
October 1 to December 31, 2005	Fixed price	300 bbl	$54.35/bbl
October 1 to December 31, 2005	Fixed price	250 bbl	$57.52/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$52.07/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$53.15/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$55.20/bbl
October 1 to December 31, 2005	Fixed price	200 bbl	$60.50/bbl
January 1 to March 31, 2006	Fixed price	300 bbl	$53.85/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$54.58/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$57.65/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$58.90/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$65.21/bbl
January 1 to March 31, 2006	Fixed price	100 bbl	$69.40/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$64.75/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$64.62/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$68.64/bbl
July 1 to September 30, 2006	Fixed price	200 bbl	$70.00/bbl
July 1 to September 30, 2006	Fixed price	200 bbl	$72.15/bbl
October 1 to December 31, 2006	Fixed price	200 bbl	$69.40/bbl
October 1 to December 31, 2006	Fixed price	200 bbl	$71.10/bbl

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.71/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.45/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.55/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.70/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.00/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.27/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.42/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.65/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.80/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$6.90/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.01/GJ
April 1 to October 31, 2005	Fixed price	5,000 GJ	$7.11/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.40/GJ

Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.50/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.60/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.70/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.80/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.91/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.01/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.15/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.22/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.32/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.50/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.72/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.55/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$9.00/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.10/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.20/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.30/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.35/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.45/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.61/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.75/GJ

As at June 30, the Trust had committed to the future sale of 489,000 barrels of crude oil at an average price of $59.92 per barrel and 26,670,000 gigajoules (GJ) of natural gas at an average price of $7.48 per GJ or $8.75 per mcf based on the historical heating value of Peyto's natural gas. These contracts will generate revenue totaling $228.7 million. Based on the market's estimate of the future commodity prices as at June 30, 2005 the fair value of these contracts would be $252.7 million.

Subsequent to June 30, 2005 the Trust entered into the following contracts:

Crude Oil **Period Hedged**	**Type**	**Daily Volume**	**Price** **(CAD)**
April 1 to June 30, 2006	Fixed price	300 bbl	$76.00/bbl
July 1 to September 30, 2006	Fixed price	300 bbl	$75.40/bbl

Natural Gas **Period Hedged**	**Type**	**Daily Volume**	**Price** **(CAD)**
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$9.75/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$8.71/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.00/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.05/GJ

8. Supplemental Cash Flow Information

	2005 **$**	**2004** **$**
Cash interest paid during the year	**4,422,402**	3,107,813
Cash taxes paid during the year	**-**	211,974

Peyto Exploration & Development Corp. Information

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Darren Gee
Vice President, Engineering

Scott Robinson
Vice President, Operations

Sandra Brick
Vice President, Finance

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Corporate Secretary

Directors

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