NEWS RELEASE

NOVEMBER 10, 2004 **SYMBOL: PEY.UN – TSX**

PEYTO ENERGY TRUST ANNOUNCES THIRD QUARTER 2004 REPORT TO UNITHOLDERS

CALGARY, ALBERTA – Peyto Energy Trust ("Peyto") is pleased to present its quarterly financial and operating results for the period ended September 30, 2004. This marks our nineteenth consecutive quarter of per unit production growth. For six years, through commodity price cycles, facility constraints and even bad weather, Peyto's team has consistently delivered successful results. The foundation of the business is our proven ability to efficiently explore for and develop natural gas resource plays. The Peyto model is working.

Quarterly Highlights:

- Cash flow per diluted unit increased 51% to $1.19
- Despite wet weather, total production increased 37% to 19,264 boe/d from the previous year and 4% from the previous quarter
- Total production increased 31% per unit after adjusting for debt and future stock based compensation
- Capital expenditures increased by 53% to $55.5 million
- Operating costs (excluding transportation) averaged $1.08/boe, 35% lower than a year ago
- Debt to cash flow ratio was 1.08 (net debt, before provision for future stock based compensation, divided by annualized Q3 2004 cash flow)
- General and administrative costs decreased 62% from the previous year to $0.05/boe
- Distributions per unit increased by 13% from the previous year while the payout ratio fell from 57% to 43%. A total of $23.3 million or $0.51 per unit was distributed to unitholders in the quarter.
- As a result of per unit production increases, Peyto announced a 12% increase in monthly distributions from $0.17 per unit per month to $0.19 per unit per month, effective for the distribution to be paid on November 15, 2004.

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).

3 Months Ended September 30	**2004**	2003	% Change
Operations			
Production			
Natural gas (mcf/d)	**91,782**	66,827	*37*
Oil & NGLs (bbl/d)	**3,967**	2,948	*35*
Barrels of oil equivalent (boe/d @ 6:1)	**19,264**	14,086	*37*
Product prices			
Natural gas ($/mcf)	**7.00**	7.02	-
Oil & NGLs ($/bbl)	**43.13**	33.86	*27*
Operating expenses ($/boe)	**1.08**	1.65	*-35*
Transportation ($/boe)	**0.68**	0.55	*24*
Field netback ($/boe)	**31.72**	29.24	*8*
General & administrative expenses ($/boe)	**0.05**	0.13	*-62*
Interest expense ($/boe)	**1.03**	1.33	*-23*
Financial ($000, except per unit)			
Revenue	**74,866**	52,365	*43*
Royalties (net of ARTC)	**15,529**	11,622	*34*
Cash flow	**54,211**	35,882	*51*
Cash flow per diluted unit	**1.19**	0.79	*51*
Cash distributions	**23,320**	20,428	*14*
Cash distributions per unit	**0.51**	0.45	*13*
Percentage of cash flow distributed	**43**	57	*-25*
Earnings*	**21,650**	25,445	*-15*
Earnings per diluted unit*	**0.47**	0.56	*-16*
Capital expenditures	**55,565**	36,280	*53*
Weighted average trust units outstanding	**45,725,272**	45,395,122	*1*

As at September 30	**2004**	2003	% Change
Net debt (before future compensation expense)	**234,731**	131,254	*79*
Unitholders' equity*	**127,085**	123,173	*3*
Total assets*	**516,385**	340,752	*52*

*Note: prior year restated for the adoption of new accounting standards for asset retirement obligations

Quarterly Review

Capital expenditures totaled $55 million and were 100% focused on internally generated drilling projects. Production averaged a record 19,264 boe per day, 37% higher than the third quarter of 2003. Over the last 12 months, our exploration and development activities have added 5,178 boe per day of low cost, long life reserves. This production has been added at the very low cost of approximately $2,900 per boe per day.

Operating costs declined 35% from the previous year to average $1.08/boe. This improvement was primarily a result of the new Peyto operated and owned gas plant at Kakwa which began processing gas in February 2004.

Activity Update

Peyto has drilled and cased 75 gross (58.4 net) gas wells to date in 2004. The success of Peyto's development of deeper Notikewin and Cadomin resource plays has contributed to an expansion of this year's capital program. In the Sundance area, 24% of our production now comes from deeper horizons. We currently have ten drilling rigs active in the Deep Basin. Half of them are in Sundance, while the other half are operating in our other core areas.

An expansion at Peyto's Kakwa gas plant from 25 mmcf/d to 35 mmcf/d is now underway and is expected to be completed by March 2005. This winter Peyto will construct a new 100% owned and operated gas plant in the Cutbank field. The Cutbank plant is expected to be selling gas by March 2005 and has been designed with an initial processing capacity of 10 mmcf/d. Once these projects are completed, Peyto will have a total of 150 mmcf/d of gas processing capacity in the Deep Basin. This winter we will be bringing on production from recent discoveries in four other areas that will initially utilize third party facilities.

Outlook

Our 2004 capital program is almost complete and capital efficiencies continue to be on trend with prior years. The number of future drilling locations we have to invest in has never been greater. As in the past, these projects will be funded with a combination of cash flow, equity and debt.

The Peyto model continues to yield superior results. By design, our capital structure is transparent and does not include exchangeable shares or convertible debentures. It is the combination of our long reserve life, low operating cost foundation, proven investment strategy and a low payout ratio that truly makes Peyto a unique trust.

If you are interested in Peyto and willing to invest some of your time to understand our past and our future we would suggest that you visit Peyto's website at www.peyto.com where you will find a current presentation, financial and historical news releases and an updated insider trading summary.

Conference Call

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2004 third quarter results on Thursday, November 11, 2004 at 9:00 a.m. Mountain Standard Time (MST), 11:00 a.m. Eastern Standard Time (EST). We will begin with a minute of silence in remembrance of those who fought and gave their lives to protect our freedom. To participate, please call 1-416-850-1243 (Toronto area) or 1-800-814-4857 for all other participants. The conference call will also be available on replay by calling 1-416-640-1917 (Toronto area) or 1-877-289-8525 for all other parties, using passcode 21100499 followed by the pound key. The replay will be available at 11:00 a.m. MST, 1:00 p.m. EST Thursday, November 11, 2004 until midnight EST on Thursday, November 18, 2004.

Don T. Gray
President and Chief Executive Officer
November 10, 2004

Certain information set forth in this document and 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'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 periods ended September 30, June 30, and March 31, 2004 and the audited consolidated financial statements, notes and related MD&A thereto of Peyto Energy Trust ("Peyto") for the year ended December 31, 2003. 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 November 9, 2004.

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 cash flow to analyze operating performance. In order to facilitate comparative analysis, cash flow is defined throughout this report as earnings before bonus, non-cash and non-recurring expenses. As presented, cash flow does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other corporations or trusts.

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 24 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 Trust will continue to monitor these developments and if it is deemed appropriate, propose an amendment to its capital structure at the next unitholders' meeting.

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, 2003, we had total proved plus probable reserves of 105.1 million barrels of oil equivalent with a reserve life of 18.8 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 prove that we have successfully implemented these principles. Our business model makes Peyto a truly unique energy trust.

Quarterly Highlights

- Increased our average production by 37 percent from the third quarter of 2003 to 19,264 boe/d.
- Increased cash flow 51 percent to $54.2 million or $1.19 per diluted unit as compared to $35.9 million or $0.79 per diluted unit in 2003.
- A total of $23.3 million or $0.51 per unit was distributed to unitholders in the quarter.

Quarterly Financial Information

	2004			2003				2002
($000 except per unit amounts)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum & natural gas sales	**74,866**	72,757	65,751	56,589	52,365	53,307	54,670	35,354
Cash flow	**54,211**	48,548	46,012	41,371	35,882	36,791	37,309	23,746
Cash flow per unit								
Basic	**1.19**	1.06	1.01	0.91	0.79	0.85	0.86	0.55
Diluted	**1.19**	1.06	1.01	0.91	0.79	0.80	0.81	0.52
Earnings (loss)*	**21,650**	30,347	24,343	6,203	25,445	(1,600)	18,531	10,323
Earnings (loss) per unit								
Basic*	**0.47**	0.66	0.53	0.14	0.56	(0.04)	0.43	0.24
Diluted*	**0.47**	0.66	0.53	0.14	0.56	(0.04)	0.40	0.23

*Note: prior periods restated for the adoption of new accounting standards for asset retirement obligations

Note: PEDC completed a reorganization into a trust effective July 1, 2003

Results of Operations

Production

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
Natural gas (mmcf/d)	**91,782**	66,827	**85,778**	62,319
Oil & natural gas liquids (bbl/d)	**3,967**	2,948	**3,722**	2,837
Barrels of oil equivalent (boe/d)	**19,264**	14,086	**18,018**	13,223

Natural gas sales averaged 91.8 mmcf/d in the third quarter of 2004, 37 percent higher than the 66.8 mmcf/d reported for the same period in 2003. Oil and natural gas liquids production averaged 3,967 bbl/d, an increase of 35 percent from 2,948 bbl/d reported in the prior year. Production for the first nine months increased 37 percent from 13,223 boe/d to 18,018 boe/d. The production increases are directly attributable to Peyto's ongoing drilling program.

Commodity Prices

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
Natural gas ($/mcf)	**6.79**	6.44	**7.43**	7.43
Oil and natural gas liquids($/bbl)	**47.64**	33.86	**45.19**	37.12
Hedging gain ($/boe)	**0.09**	2.75	**0.08**	1.43

Our natural gas price before hedging averaged $6.79/mcf during the third quarter of 2004, an increase of 5 percent from $6.44/mcf reported for the equivalent period in 2003. Oil and natural gas liquids prices averaged $47.64/bbl up 41 percent from $33.86/bbl a year earlier. Natural gas prices for the first nine months were unchanged at $7.43/mcf and oil and natural gas liquids prices up 22 percent at $45.19/bbl compared to 2003. 2004 year to date hedging activity accounted for $0.08/boe of Peyto's price achieved. Expectations are for commodity prices to remain strong relative to historical pricing.

Revenue

	Three months ended Sept. 30		Nine months ended Sept. 30	
($000)	**2004**	2003	**2004**	2003
Natural gas	**57,322**	39,622	**168,429**	126,431
Oil and natural gas liquids	**17,387**	9,184	**44,553**	28,752
Hedging gain	**157**	3,559	**392**	5,159
Total revenue	**74,866**	52,365	**213,374**	160,342

For the three months ended September 30, 2004, gross revenue increased 43 percent to $74.9 million from $52.4 million for the same period in 2003. Year to date revenue was up 33 percent as a result of increased production volumes in combination with higher oil and natural gas liquids prices.

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 Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
Royalties, net of ARTC ($000)	**15,529**	11,622	**49,986**	39,309
% of sales	**21**	23	**24**	25
$/boe	**8.76**	8.97	**10.12**	10.89

For the third quarter of 2004, royalties averaged $8.76/boe or approximately 21 percent of Peyto's total petroleum and natural gas sales price of $42.24/boe. Lower current royalty rates are a result of Peyto's drilling program that is increasingly targeting deeper horizons that are eligible for deep gas royalty holidays. Year to date royalties were 24 percent of sales in 2004 compared to 25 percent in 2003. 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 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 Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
Operating costs ($000)				
Field expenses	**2,951**	3,032	**8,203**	6,876
Processing and gathering income	**-1,036**	-891	**-2,946**	-2,661
Total operating costs	**1,915**	2,141	**5,257**	4,215
$/boe	**1.08**	1.65	**1.06**	1.17
Transportation	**1,208**	707	**3,311**	2,029
$/boe	**0.68**	0.55	**0.67**	0.56

Operating costs were $1.9 million in the third quarter compared to $2.1 million during the same period a year earlier. On a unit-of-production basis, operating costs averaged $1.08/boe compared to $1.65/boe for the third quarter of 2003. Year to date operating costs averaged $1.06/boe in 2004 compared to $1.17/boe in 2003.

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 Sept. 30		Nine months ended Sept. 30	
($/boe)	**2004**	2003	**2004**	2003
Sale Price	**42.24**	40.41	**43.22**	44.42
Less:				
Royalties	**8.76**	8.97	**10.12**	10.89
Operating costs	**1.08**	1.65	**1.06**	1.17
Transportation	**0.68**	0.55	**0.67**	0.56
Operating netback	**31.72**	29.24	**31.37**	31.80
General and administrative	**0.05**	0.13	**0.16**	0.21
Interest on long-term debt	**1.03**	1.33	**1.00**	1.00
Capital tax	**0.05**	-0.09	**0.06**	0.11
Cash netback	**30.59**	27.87	**30.15**	30.48

General and Administrative Expenses

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
G&A expenses ($000)	**1,048**	787	**3,142**	2,332
Overhead recoveries	**-967**	-614	**-2,349**	-1,568
Net G&A expenses	**81**	173	**793**	764
$/boe	**0.05**	0.13	**0.16**	0.21

General and administrative expenses before overhead recoveries increased to $1.0 million in the third quarter of 2004, as compared to $0.8 million for the same period in 2003 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 $0.05 per boe from $0.13 per boe in 2003. Year to date general and administrative expenses averaged $0.16/boe in 2004 compared to $0.21 in 2003.

Interest Expense

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
Interest expense ($000)	**1,833**	1,729	**4,941**	3,608
$/boe	**1.03**	1.33	**1.00**	1.00

Third quarter interest expense was $1.8 million or $1.03/boe compared to $1.7 million or $1.33/boe a year earlier. During the first nine months of 2004, average debt levels 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 current quarter provision for depletion, depreciation and accretion totaled $11.8 million as compared to $5.8 million in 2003. Year to date DD&A totaled $30.1 million in 2004 compared to $15.9 million in 2003. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $6.10/boe as compared to $4.48/boe in 2003. Increases or decreases in the depletion rate on a unit-of-production basis will be influenced by the reserves added through the 2004 drilling program. As set out under the section "Changes in Accounting Policies", Peyto adopted the CICA pronouncement with respect to Asset Retirement Obligations, effective January 1, 2004.

Income Taxes

The current provision for future income tax increased to $10.4 million in the first nine months of 2004 from $7.5 million in the same period of 2003. The change is due to the 73 percent increase in pre-tax earnings in 2004 resulting from higher production volumes.

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 nine months of 2004, we recorded a hedging gain of $0.4 million as compared to $5.2 million in the first nine months of 2003. As set out under the section "Changes in Accounting Policies", we have adopted, effective January 1, 2004, the new CICA Accounting Guideline 13 with respect to Hedging Relationships. A summary of contracts outstanding in respect of the hedging activities are as follows:

Oil Period Hedged	Type	Daily Volume	Price (CAD)
July 1 to September 30, 2004	Fixed price	1,000 bbl	$39.41/bbl
October 1 to December 31, 2004	Fixed price	1,000 bbl	$38.29/bbl
January 1 to March 31, 2005	Fixed price	500 bbl	$50.85/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$50.65/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$53.25/bbl
January 1 to March 31, 2005	Fixed price	300 bbl	$57.50/bbl
April 1 to June 30, 2005	Fixed price	500 bbl	$48.85/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$49.25/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$51.85/bbl
April 1 to June 30, 2005	Fixed price	300 bbl	$57.35/bbl
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
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

Natural Gas Period Hedged	Type	Daily Volume	Floor (CAD)	Ceiling (CAD)
April 1 to October 31, 2004	Costless collar	10,000 GJ	$5.00/GJ	$6.50/GJ
April 1 to October 31, 2004	Costless collar	5,000 GJ	$5.00/GJ	$7.10/GJ
April 1 to October 31, 2004	Costless collar	5,000 GJ	$5.00/GJ	$7.41/GJ
April 1 to October 31, 2004	Fixed price	10,000 GJ	$5.64/GJ	
April 1 to October 31, 2004	Fixed price	5,000 GJ	$5.89/GJ	
April 1 to October 31, 2004	Fixed price	5,000 GJ	$5.97/GJ	
April 1 to October 31, 2004	Fixed price	5,000 GJ	$6.25/GJ	
May 1 to October 31, 2004	Fixed price	5,000 GJ	$6.21/GJ	
Nov. 1 to Dec. 31, 2004	Fixed price	5,000 GJ	$7.80/GJ	
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$5.50/GJ	$8.00/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.65/GJ	
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$6.00/GJ	$7.65/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	10,000 GJ	$6.97/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.95/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.08/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.14/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.56/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.75/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.50/GJ	
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	

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 fluctuations in interest rates on our floating rate long-term debt. Currently we have not entered into any agreements to manage this risk.

Liquidity and Capital Resources

Cash Flow

	Three months ended Sept. 30		Nine months ended Sept. 30	
($000)	**2004**	2003	**2004**	2003
Earnings*	**21,650**	25,445	**76,340**	42,376
Items not requiring cash:				
Non-cash provision for bonuses	**20,298**	-	**31,910**	-
Future income tax expense	**490**	4,619	**10,418**	7,498
Depletion, depreciation & accretion*	**11,773**	5,818	**30,103**	15,956
Non-recurring items:				
Trust reorganization costs	**-**	-	**-**	44,206
Cash flow	**54,211**	35,882	**148,771**	110,036

*Note: prior period restated for the adoption of new accounting standards for asset retirement obligations

For the quarter ended September 30, 2004, cash flow from operations totaled $54.2 million or $1.19 per unit, representing a 51 percent increase from the $35.9 million, or $0.79 per diluted unit during the same period in 2003. Year to date cash flow totaled $148.8 million or $3.25 per unit in 2004 compared to $110.0 million or $2.49 per unit in 2003. Peyto's policy is to distribute approximately 50% of cash flow 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 cash flow and capital expenditure budget. Accordingly, we will assess results throughout the year and revise budgets 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 $300 million including a $280 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 September 30, 2004, $190 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At September 30, 2004, we had a working capital deficit of $72.2 million.

We believe that funds generated from our operations, together with borrowings under our credit facility and proceeds from any equity issued will be sufficient to finance our current operations and planned capital expenditure program. We anticipate that our 2004 capital expenditures will be between $180 and $220 million. In 2004, primarily 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

As at September 30 and November 9, 2004, 45.7 million trust units were outstanding.

Trust Units:

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

Trust Units (no par value)	Number of Units	Amount
Balance, December 31, 2003	45,395,122	$49,227,530
Trust units issued by private placement	330,150	9,013,095
Balance, September 30, 2004	45,725,272	$58,240,625

Stock Based Compensation & Bonus Plan

The Trust has a bonus plan made up of market and reserves based components that were established upon the trust reorganization.

Under the reserves based component, the bonus pool 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 and a discount rate of 8%. As the reserves component is calculated based on the year end independent reserves evaluation, it is determinable only at year end and no provision will be recorded until the relevant information is available.

Under the market based component, rights initially issued with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time shall not 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 is then applied to the result in order to make the bonus plan approximate the previous stock option plan on an after tax basis.

Compensation costs related to the non-vested rights as at September 30, 2004 was $73.0 million of which a non-cash provision for future compensation expense of $12.5 million was recorded at December 31, 2003 and an additional $31.9 million was recorded in the first nine months of 2004.

Capital Expenditures

Capital expenditures to date in 2004 total $153.8 million. Exploration and development related activity represented $112.4 million or 73% of the total, while expenditures on facilities, gathering systems and equipment totaled $38.1 million or 25% of the total. The following table summarizes capital expenditures for the first nine months of the year.

	Three months ended Sept. 30		Nine months ended Sept. 30	
($000)	**2004**	2003	**2004**	2003
Land	**568**	420	**3,203**	1,627
Seismic	**1,094**	634	**2,454**	1,136
Drilling – Exploratory & Development	**44,824**	30,195	**106,734**	77,706
Production Equipment, Facilities & Pipelines	**8,972**	4,847	**38,099**	14,749
Acquisitions & Dispositions	**104**	175	**3,255**	378
Office Equipment	**3**	9	**75**	64
Total capital expenditures	**55,565**	36,280	**153,820**	95,660

Cash Distributions

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
Cash flow from operations ($000)	**54,211**	35,882	**148,771**	110,036
Distributions ($000)	**23,320**	20,428	**67,216**	20,428
Distributions per unit ($)	**0.51**	0.45	**1.47**	0.45
Payout ratio (%)	**43**	57	**45**	19

We distribute a portion of cash flow from operations to our unitholders on a monthly basis with a portion of this cash flow 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:

($000s)	Remainder of 2004	2005	2006	2007
Office lease	104	418	364	364

Guarantees/Off-Balance Sheet Arrangements

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contract 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 nine months of 2004, the Trust paid distributions to the unitholders in the amount of $67.2 million (2003 - $20.4 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit
January 2004	January 30, 2004	February 16, 2004	$0.15
February 2004	February 27, 2004	March 15, 2004	$0.15
March 2004	March 31, 2004	April 15, 2004	$0.15
April 2004	April 30, 2004	May 14, 2004	$0.17
May 2004	May 31, 2004	June 15, 2004	$0.17
June 2004	June 30, 2004	July 15, 2004	$0.17
July 2004	July 30, 2004	August 16, 2004	$0.17
August 2004	August 31, 2004	September 15, 2004	$0.17
September 2004	September 30, 2004	October 15, 2004	$0.17
Total			$1.47

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 cash flow from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the cash flow paid to investors and the value of the units are subject to numerous risks inherent in the oil and natural gas industry.

Our expected cash flow 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.

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 the business development team and perform stringent levels of due diligence on our analysis of acquisition targets, including a detailed examination of reserve reports; 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 cash flow, debt and 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. 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, 2003 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 5 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.

In applying the full cost method, the total capitalized costs less accumulated depletion, depreciation and future income taxes are limited to an amount equal to the estimated future net revenue from proven reserves (based on prices and costs at the balance sheet date) plus the cost (net of impairments) of unproven properties less estimated future site restoration costs, general administrative expenses, financing costs and income taxes. Any deficiency in the future recoverable costs as compared to the net book value is charged to current operations as part of depletion and depreciation expense.

Changes in Accounting Policies

Hedging Relationships

The Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13 – Hedging Relationships, which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline establishes conditions for applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. We enter into numerous financial instruments to manage our commodity price risk that qualify as hedges under the new accounting guideline. Effective January 1, 2004, we have elected to apply hedge accounting to all of our financial instruments.

Asset Retirement Obligations

The CICA issued Section 3110 Asset Retirement Obligations to harmonize Canadian GAAP with Financial Accounting Standards Board Statement No. 143. The section replaces previous guidance on future removal and site restoration costs and is effective for fiscal years beginning on or after January 1, 2004. The asset retirement obligation liability will initially be measured at fair value, which is the discounted future value of the liability. The liability accretes until the obligation is settled. The fair value is capitalized as part of the related asset and is depleted over the useful life of the asset. Prior periods have been restated in accordance with the new standard.

Full Cost Accounting

The CICA issued Accounting Guideline 16 which replaces Accounting Guideline 5, Full Cost Accounting in the Oil and Gas Industry. The guideline is effective for fiscal years beginning on or after January 1, 2004 and is to be accounted for on a prospective basis. The most significant change is the modification of the ceiling test to be consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline limits the carrying value of oil and gas properties to their fair value. There is no write down of our property, plant and equipment under the new method as of September 30, 2004.

Continuous Disclosure Obligations

Effective March 31, 2004, the Trust and all reporting issuers in Canada have become subject to new disclosure requirements pursuant to National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and Annual Information Form (AIF). The instrument also requires enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Trust to mail annual and interim financial statements and MD&A to unitholders, but rather these documents will be provided on an "as requested" basis. The Trust continues to assess the implications of this new instrument which has been implemented in 2004.

Additional Information

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

Quarterly information

	2004			2003	
	Q3	Q2	Q1	Q4	Q3
Operations					
Production					
Natural gas (mcf/d)	**91,782**	87,753	78,597	73,013	66,827
Oil & NGLs (bbl/d)	**3,967**	3,918	3,315	3,104	2,948
Barrels of oil equivalent (boe/d @ 6:1)	**19,264**	18,544	16,414	15,273	14,086
Average product prices					
Natural gas ($/mcf)	**7.00**	7.32	7.63	6.93	7.02
Oil & natural gas liquids ($/bbl)	**43.13**	40.06	39.59	35.22	33.86
Average operating expenses ($/boe)	**1.08**	1.04	1.08	1.63	1.65
Average transportation costs ($/boe)	**0.68**	0.74	0.58	0.56	0.55
Field netback ($/boe)	**31.72**	30.14	32.32	30.48	29.24
General & administrative expense ($/boe)	**0.05**	0.30	0.14	0.10	0.13
Interest expense ($/boe)	**1.03**	0.99	0.97	0.80	1.33
Financial ($000 except per unit)					
Revenue	**74,866**	72,757	65,751	56,589	52,365
Royalties (net of ARTC)	**15,529**	18,904	15,553	10,688	11,622
Cash flow	**54,211**	48,548	46,012	41,371	35,882
Cash flow per diluted unit	**1.19**	1.06	1.01	0.91	0.79
Cash distributions	**23,320**	23,320	20,576	20,428	20,428
Cash distributions per unit	**0.51**	0.51	0.45	0.45	0.45
Percentage of cash flow distributed	**43%**	48%	45%	50%	57%
Earnings*	**21,650**	30,347	24,343	6,203	25,445
Earnings per diluted unit*	**0.47**	0.66	0.53	0.14	0.56
Capital expenditures	**55,565**	37,067	61,187	43,763	36,280
Weighted average trust units outstanding	**45,725,272**	45,725,272	45,721,644	45,395,122	45,395,122

*Note: restated for the adoption of new accounting standards for asset retirement obligations

Peyto Energy Trust

Consolidated Balance Sheets

(unaudited)

	September 30, 2004 $	December 31, 2003 (restated – Note 1) $
Assets		
Current		
Cash	**-**	20,591,218
Accounts receivable	**46,201,580**	41,110,278
Due from private placement	**-**	9,013,095
Prepaids and deposits	**5,489,210**	5,132,281
	51,690,790	75,846,872
Property, plant and equipment *(Notes 2 and 3)*	**464,694,150**	340,298,794
	516,384,940	416,145,666
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**88,471,550**	81,426,984
Capital taxes payable	**177,106**	76,726
Cash distributions payable	**7,773,306**	6,809,268
Provision for future market based bonus *(Note 7)*	**27,435,025**	7,515,119
	123,856,987	95,828,097
Long-term debt *(Note 3)*	**190,000,000**	150,000,000
Provision for future market based bonus *(Note 7)*	**16,950,347**	4,959,979
Asset retirement obligations *(Note 8)*	**2,957,291**	2,279,411
Future income taxes	**55,535,227**	45,116,704
	265,442,865	202,356,094
Unitholders' equity		
Unitholders' capital *(Note 4)*	**58,240,625**	49,227,530
Units to be issued	**-**	9,013,095
Accumulated earnings	**176,916,323**	100,576,460
Accumulated cash distributions *(Note 5)*	**(108,071,860)**	(40,855,610)
	127,085,088	117,961,475
	516,384,940	416,145,666

See accompanying notes

On behalf of the Board:

(signed) *"Ritchie F. Braund"*
Director

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

Peyto Energy Trust

Consolidated Statements of Earnings and Accumulated Earnings

(unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003 (restated – Note 1)	**2004**	2003 (restated – Note 1)
	$	$	**$**	$
Revenue				
Petroleum and natural gas sales, net	**59,337,285**	40,743,379	**163,387,870**	121,033,586
Expenses				
Operating *(Note 6)*	**1,914,825**	2,140,834	**5,256,728**	4,214,962
Transportation	**1,207,772**	707,178	**3,310,547**	2,029,115
General and administrative	**81,394**	173,493	**793,222**	764,342
Future market based bonus provision *(Note 7)*	**20,298,782**	-	**31,910,274**	-
Interest	**1,832,995**	1,729,125	**4,940,808**	3,608,466
Trust reorganization	**-**	-	**-**	44,206,442
Depletion, depreciation and accretion *(Note 8)*	**11,772,970**	5,818,273	**30,102,702**	15,955,789
	37,108,738	10,568,903	**76,314,281**	70,779,116
Earnings before taxes	**22,228,547**	30,174,476	**87,073,589**	50,254,470
Taxes				
Future income tax expense	**489,816**	4,618,746	**10,418,523**	7,498,670
Capital tax expense	**89,184**	110,621	**315,202**	380,134
	579,000	4,729,367	**10,733,725**	7,878,804
Net earnings for the period	**21,649,547**	25,445,109	**76,339,864**	42,375,666
Accumulated earnings, beginning of period	**154,943,534**	68,688,761	**100,253,217**	51,835,681
Retroactive application of change in accounting policy *(Note 1)*	**323,242**	239,256	**323,242**	161,779
Accumulated earnings, beginning of period, as restated	**155,266,776**	68,928,017	**100,576,459**	51,997,460
Accumulated earnings, end of period	**176,916,323**	94,373,126	**176,916,323**	94,373,126
Earnings (loss) per unit *(Note 4)*				
Basic	**0.47**	0.56	**1.67**	0.95
Diluted	**0.47**	0.56	**1.67**	0.95

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Cash Flows

(unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003 (restated – Note 1)	**2004**	2003 (restated – Note 1)
	$	$	**$**	$
Cash provided by (used in)				
Operating Activities				
Net earnings for the period	**21,649,547**	25,445,109	**76,339,864**	42,375,666
Items not requiring cash:				
Non-cash provision for bonuses	**20,298,782**	-	**31,910,274**	-
Future income tax expense	**489,816**	4,618,746	**10,418,523**	7,498,670
Depletion, depreciation and accretion	**11,772,970**	5,818,273	**30,102,702**	15,955,789
Change in non-cash working capital related to operating activities	**6,707,554**	1,960,321	**1,100,553**	2,174,014
	60,918,669	37,842,449	**149,871,916**	68,004,139
Financing Activities				
Issue of trust units, net of costs	**-**	29,874,730	**-**	29,989,166
Distribution payments	**(23,319,920)**	(13,618,536)	**(67,216,250)**	(13,618,536)
Increase in bank debt	**10,000,000**	(23,178,369)	**40,000,000**	20,000,000
Change in non-cash working capital related to financing activities	**-**	-	**9,977,133**	-
	(13,319,920)	(6,922,175)	**(17,239,117)**	36,370,630
Investing Activities				
Additions to property, plant and equipment	**(55,565,543)**	(36,280,091)	**(153,820,178)**	(95,660,295)
Change in non-cash working capital related to investing activities	**7,966,794**	13,562,777	**596,161**	(658,436)
	(47,598,749)	(22,717,314)	**(153,224,017)**	(96,318,731)
Net increase (decrease) in cash	**-**	8,202,960	**(20,591,218)**	8,056,038
Cash, beginning of period	**-**	58,636	**20,591,218**	205,558
Cash, end of period	**-**	8,261,596	**-**	8,261,596

Supplementary cash flow information				
Interest paid during the period	**1,832,995**	1,729,125	**4,940,808**	3,608,466
Income taxes paid during the period	**-**	101,436	**214,822**	471,776

See accompanying notes

Peyto Energy Trust

Notes to Consolidated Financial Statements

September 30, 2004 and 2003 (unaudited)

1. Summary of 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 except as discussed below. 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 2003 audited consolidated financial statements.

These financial statements include the accounts of Peyto Energy Trust and its wholly owned subsidiaries.

(a) Asset Retirement Obligations

On January 1, 2004, Peyto adopted the new CICA Handbook section 3110, Asset Retirement Obligations. This standard focuses on the recognition and measurement of liabilities related to legal obligations associated with the retirement of property, plant and equipment. Under this standard, these obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes in the underlying cash flows. The asset retirement obligation is to be capitalized to the related asset and amortized into earnings over time. The new accounting policy has been applied retroactively with restatement of prior periods. As a result of the retroactive application, the comparative statement of earnings has been restated. The effect of the change on net earnings for the three and nine month periods ended September 30, 2004 and 2003 was immaterial.

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

	As previously Reported $	Adjustment $	As Restated $
Property, plant and equipment	338,413,384	1,885,410	340,298,794
Asset retirement obligations liability	888,407	1,391,004	2,279,411
Future income tax liability	44,945,541	171,163	45,116,704
Accumulated earnings	100,253,217	323,243	100,576,460

(b) Hedge Accounting

The CICA issued Accounting Guideline 13, Hedging Relationships, effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue using hedge accounting. Peyto's hedges qualify for the use of hedge accounting and Peyto has elected to apply hedge accounting.

(c) Full Cost Accounting

The CICA issued Accounting Guideline 16, Oil & Gas Accounting – Full Cost. The guideline is effective for fiscal years beginning on or after January 1, 2004 and is to be accounted for on a prospective basis. The most significant change is in the modification of the ceiling test to be consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline limits the carrying value of oil and gas properties to their fair value. The Trust adopted the guideline effective January 1, 2004 and as at January 1, 2004 and September 30, 2004, there were no indications of impairment. The impairment test was calculated using the independent engineering consultant's average prices at December 31, 2003 as follows:

	2004	2005	2006	2007	2008	Thereafter
WTI ($US/bbl)	29.00	26.50	25.50	25.00	25.50	+2%
AECO ($CDN/mcf)	6.00	5.31	4.83	4.87	4.92	+2%

2. Property, Plant and Equipment

	2004 $	2003 $
Property, plant and equipment	**539,154,753**	384,788,369
Accumulated depletion and depreciation	**(74,460,603)**	(44,489,575)
	464,694,150	340,298,794

At September 30, 2004 costs of $25,319,789 (December 31, 2003 - $25,319,789) related to undeveloped land have been excluded from the depletion and depreciation calculation. Amounts related to 2003 have been restated for the adoption of new accounting standards for asset retirement obligations.

3. Long-Term Debt

The Trust has a syndicated $300 million extendible, 364 day revolving credit facility, followed by a one year non-revolving term-out period. The facility is made up of a $20 million working capital sub-tranche and a $280 million production line. 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 (no par value)	**Number of Units**	**Amount** **$**
Balance, December 31, 2003	45,395,122	49,227,530
Trust units issued by private placement	330,150	9,013,095
Balance, September 30, 2004	45,725,272	58,240,625

Per Unit Amounts

Earnings per unit have been calculated based upon the weighted average number of units outstanding during the three and nine month periods ended September 30, 2004 of 45,725,272 and 45,724,067 respectively (September 30, 2003 – 45,395,122 and 44,104,799).

5. Accumulated Cash Distributions

During the period, the Trust paid distributions to the unitholders in the aggregate amount of $67.2 million (2003 - $20.4 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit
January 2004	January 30, 2004	February 16, 2004	$0.15
February 2004	February 27, 2004	March 15, 2004	$0.15
March 2004	March 31, 2004	April 15, 2004	$0.15
April 2004	April 30, 2004	May 14, 2004	$0.17
May 2004	May 31, 2004	June 15, 2004	$0.17
June 2004	June 30, 2004	July 15, 2004	$0.17
July 2004	July 30, 2004	August 16, 2004	$0.17
August 2004	August 31, 2004	September 15, 2004	$0.17
September 2004	September 30, 2004	October 15, 2004	$0.17

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 September 30		Nine Months ended September 30	
	2004	2003	**2004**	2003
	$	$	**$**	$
Field expenses	**2,950,973**	3,031,827	**8,203,264**	6,875,580
Processing and gathering income	**(1,036,148)**	(890,993)	**(2,946,536)**	(2,660,618)
Total operating costs	**1,914,825**	2,140,834	**5,256,728**	4,214,962

7. Market and Reserves Based Bonus Plan

The Trust has a bonus plan made up of market and reserves based components.

Under the reserves based component, the bonus pool 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 and a discount rate of 8%. As the reserves component is calculated based on the year end independent reserves evaluation, it is determinable only at year end and no provision will be recorded until the relevant information is available.

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 is then applied to the result in order to make the bonus plan approximate the previous stock option plan on an after tax basis.

Compensation costs related to the non-vested rights as at September 30, 2004 was $73.0 million of which a non-cash provision for future compensation expense of $12.5 million was recorded at December 31, 2003 and an additional $31.9 million was recorded in 2004.

8. Asset Retirement Obligations

The total future asset retirement obligations are estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligations to be $2.9 million as at September 30, 2004 based on a total future liability of $12.8 million. These payments are expected to be made over the next 50 years. The Trust's credit adjusted risk free rate of 7% and an inflation rate of 2% were used to calculate the present value of the asset retirement obligation.

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

	$
Carrying amount, as at December 31, 2003, as restated	2,279,411
Increase in liabilities during the period	546,206
Settlement of liabilities during the period	-
Accretion expense	131,674
Carrying amount, as at September 30, 2004	2,957,291

9. 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 oil and natural gas prices. A summary of contracts outstanding in respect of the hedging activities at September 30, 2004 were as follows:

Oil Period Hedged	Type	Daily Volume	Price (CAD)
July 1 to September 30, 2004	Fixed price	1,000 bbl	$39.41/bbl
October 1 to December 31, 2004	Fixed price	1,000 bbl	$38.29/bbl
January 1 to March 31, 2005	Fixed price	500 bbl	$50.85/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$50.65/bbl
January 1 to March 31, 2005	Fixed price	200 bbl	$53.25/bbl
January 1 to March 31, 2005	Fixed price	300 bbl	$57.50/bbl
April 1 to June 30, 2005	Fixed price	500 bbl	$48.85/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$49.25/bbl
April 1 to June 30, 2005	Fixed price	200 bbl	$51.85/bbl
April 1 to June 30, 2005	Fixed price	300 bbl	$57.35/bbl
July 1 to September 30, 2005	Fixed price	250 bbl	$54.08/bbl

Natural Gas Period Hedged	Type	Daily Volume	Floor (CAD)	Ceiling (CAD)
April 1 to October 31, 2004	Costless collar	10,000 GJ	$5.00/GJ	$6.50/GJ
April 1 to October 31, 2004	Costless collar	5,000 GJ	$5.00/GJ	$7.10/GJ
April 1 to October 31, 2004	Costless collar	5,000 GJ	$5.00/GJ	$7.41/GJ
April 1 to October 31, 2004	Fixed price	10,000 GJ	$5.64/GJ	
April 1 to October 31, 2004	Fixed price	5,000 GJ	$5.89/GJ	
April 1 to October 31, 2004	Fixed price	5,000 GJ	$5.97/GJ	
April 1 to October 31, 2004	Fixed price	5,000 GJ	$6.25/GJ	
May 1 to October 31, 2004	Fixed price	5,000 GJ	$6.21/GJ	
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$5.50/GJ	$8.00/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.65/GJ	
Nov. 1, 2004 to March 31, 2005	Costless collar	10,000 GJ	$6.00/GJ	$7.65/GJ
Nov. 1, 2004 to March 31, 2005	Fixed price	10,000 GJ	$6.97/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$6.95/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.08/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.14/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.56/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.75/GJ	
Nov. 1, 2004 to March 31, 2005	Fixed price	5,000 GJ	$7.50/GJ	
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	

Based on dealer quotes, had these contracts been closed on September 30, 2004, the Trust would have realized a loss in the amount of $10,729,357.

Subsequent to September 30, 2004 the Trust entered into the following contracts:

Oil Period Hedged	Type	Daily Volume	Price (CAD)
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
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

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
Nov. 1 to Dec. 31, 2004	Fixed price	5,000 GJ	$7.80/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

Peyto Exploration & Development Corp. Information

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