NEWS RELEASE

MARCH 10, 2010 **SYMBOL: PEY.UN – TSX**

PEYTO ENERGY TRUST ANNOUNCES Q4 AND 2009 YEAR END REPORT TO UNITHOLDERS

CALGARY, ALBERTA – Peyto Energy Trust ("Peyto" or the "Trust") is pleased to present the operating and financial results for the fourth quarter and 2009 fiscal year. In a year of unprecedented financial turmoil, Peyto's industry leading cost structure, top quality assets and disciplined capital investment strategy delivered unitholders a 74% operating margin(1), 56% profit margin(2), 12% return on capital employed, and a 28% return on equity. The following summarizes Peyto's accomplishments in 2009:

- Invested $73 million of capital (net of $11.3 million in Drilling Royalty Credits) to find and develop 32 BCFe of new Proved Producing ("PP") reserves. All in FD&A costs for PP, Total Proved ("TP") and Proved plus Probable Additional ("P+P") reserves were $2.26/MCFe, $1.73/MCFe and $1.47/MCFe ($8.80/boe) including changes in future development capital.

- Grew Total Proved reserves to 893 BCFe and Proved plus Probable Additional reserves to 1.2 TCFe. The successful application of horizontal multi-stage fracture technology helped increase the Total Proved undeveloped reserves by 77% or 112 BCFe and the total P+P undeveloped reserves by 190% or 207 BCFe.

- Built 25 MMCFe/d (4,200 boe/d) of new production at a cost of $17,300/boe/d, down 48% from $33,100/boe/d in 2008.

- Maintained a low cost advantage with operating costs of $0.41/MCFe ($2.48/boe), similar to 2008 at $0.44/MCFe ($2.60/boe).

- Generated $203 million in Funds from Operations ($1.83/unit) and $153 million in Earnings ($1.38/unit).

- Reduced net debt by $52.8 million to $439.9 million, leaving $110 million of available capacity on bank lines of $550 million.

- Distributed $163.3 million to unitholders ($1.47/unit).

- Net Asset value or the NPV per unit, debt adjusted (discounted at 5%) of the Proved plus Probable Additional assets remained at $33/unit.

2009 in Review

Peyto has now completed its eleventh year of operations. In all respects it was a challenging year, as a continuous slide in natural gas prices (AECO daily average) which began in June of 2008 at $10.60/GJ, finally ended in August of 2009 at $2.61/GJ, a 75% drop. Natural gas prices then recovered to end the year at $5.23/GJ. Meanwhile, the global economies and capital markets of the world continued to struggle under the pressure of a recession. Unitholders of Peyto were able to take comfort in the Trust's low operating costs, strong hedge book and high quality, long reserve life assets to protect them during this volatile time. The Trust reduced distributions in response to these economic conditions and issued equity midway through the year. Both served to increase the financial flexibility of the business and allowed Peyto to capitalize on drilling opportunities prior to the recovery in both natural gas prices and industry activity. These opportunities, which included proving the application of horizontal multi-stage fracture technology on Peyto's Deep Basin tight gas resource plays, have served to significantly increase the amount of undeveloped potential in Peyto's asset base. Combined with short term Alberta royalty incentives, these future opportunities have some of the lowest natural gas supply costs in North America and should provide Peyto with growth in the future.

(1) Operating Margin is defined as Funds from Operations divided by Revenue before Royalties but including realized hedging gains (losses).
(2) Profit Margin is defined as Net Earnings for the year divided by Revenue before Royalties but including realized hedging gains (losses).
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). Natural gas liquids and oil volumes in barrel of oil (bbl) are converted to thousand cubic feet equivalent (mcfe) using a ratio of one (1) barrel of oil to six (6) thousand cubic feet. This could be misleading if used in isolation as it is based on an energy equivalency conversion method primarily applied at the burner tip and does not represent a value equivalency at the wellhead.

	3 Months Ended December 31		%	12 Months Ended December 31		%
	2009	2008	Change	**2009**	2008	Change
Operations						
Production						
Natural gas (mcf/d)	**95,467**	101,907	*(6)%*	**92,718**	100,384	*(8)%*
Oil & NGLs (bbl/d)	**3,222**	3,207	*0%*	**3,028**	3,265	*(7)%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**114,798**	121,146	*(5)%*	**110,884**	119,975	*(8)%*
Barrels of oil equivalent (boe/d @ 6:1)	**19,133**	20,191	*(5)%*	**18,481**	19,996	*(8)%*
Product prices						
Natural gas ($/mcf)	**6.17**	7.99	*(23)%*	**6.44**	8.64	*(25)%*
Oil & NGLs ($/bbl)	**60.77**	46.16	*32%*	**50.18**	84.78	*(41)%*
Operating expenses ($/mcfe)	**0.38**	0.43	*(12)%*	**0.41**	0.44	*(6)%*
Transportation ($/mcfe)	**0.11**	0.10	*10%*	**0.11**	0.10	*10%*
Field netback ($/mcfe)	**5.64**	6.61	*(15)%*	**5.60**	7.18	*(22)%*
General & administrative expenses ($/mcfe)	**0.15**	0.11	*36%*	**0.18**	0.15	*20%*
Interest expense ($/mcfe)	**0.44**	0.45	*(2)%*	**0.41**	0.50	*(18)%*
Financial ($000, except per unit)						
Revenue	**72,218**	89,377	*(19)%*	**273,517**	418,885	*(35)%*
Royalties	**7,457**	9,765	*(24)%*	**25,671**	79,821	*(68)%*
Funds from operations	**53,302**	67,354	*(21)%*	**202,699**	286,907	*(29)%*
Funds from operations per unit	**0.46**	0.64	*(28)%*	**1.83**	2.71	*(32)%*
Total distributions	**41,371**	47,664	*(13)%*	**163,263**	186,731	*(13)%*
Total distributions per unit	**0.36**	0.45	*(20)%*	**1.47**	1.76	*(16)%*
Payout ratio	**78**	71	*10%*	**81**	65	*25%*
Earnings	**33,035**	50,711	*(35)%*	**152,774**	179,397	*(15)%*
Earnings per diluted unit	**0.28**	0.48	*(42)%*	**1.38**	1.69	*(18)%*
Capital expenditures	**26,307**	22,467	*17%*	**72,739**	139,324	*(48)%*
Weighted average trust units outstanding	**114,920,194**	105,920,194	*8%*	**110,555,810**	105,876,470	*4%*
As at December 31						
Net debt (before future compensation expense and unrealized hedging gains)				**439,860**	492,644	*11%*
Unitholders' equity				**612,483**	550,717	*11%*
Total assets				**1,254,113**	1,280,246	*(2)%*
Earnings	**33,035**	50,711		**152,774**	179,397	
Expenditures on site restoration and reclamation	**(51)**	-		**(51)**	-	
Items not requiring cash:						
Future income tax expense	**(5,065)**	1,778		**(31,444)**	32,111	
Depletion, depreciation and accretion	**19,037**	19,901		**73,298**	75,668	
Change in non-cash working capital	**(389)**	(24,276)		**4,111**	(39,055)	
Cash flows from operating activities	**46,567**	48,114		**198,688**	248,121	
Change in provision for performance based compensation	**1,266**	(5,036)		**3,042**	(269)	
Performance based compensation	**5,080**	-		**5,080**	-	
Change in non-cash working capital	**389**	24,276		**(4,111))**	39,055	
Funds from operations [(1)]	**53,302**	67,354		**202,699**	286,907	

(1) 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 performance based compensation, non-cash and non-recurring expenses. Management believes 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.

Capital Expenditures

Net capital expenditures for 2009 totaled $72.7 million, a 48% decrease from 2008. Capital invested represented 36% of annual cash flow with over 75% of the investment occurring in the last half of the year as commodity prices began to improve. As is typical of Peyto's design, drill and build strategy, over 90% of the capital was invested in well related activity with $44.2 million in drilling, $22.7 million in completions, and $11.4 million in wellsite equipment, pipelines and facilities. The remaining $5.5 million was invested in new lands and seismic with 31 new sections of Deep Basin lands being added at $130/ac or at just 20% of 2008 prices. In total, $11.3 million of drilling royalty credit ("DRC") was earned, with $6.0 million claimed by the end of the year and $5.3 million yet to be claimed, reducing total capital by 13.5%.

The majority of the capital invested in 2009 was in the Greater Sundance core area where horizontal drilling technology was evaluated in three different formations; the Cardium, Notikewin and Wilrich. The remaining capital was spent on faulted Cardium development in the Ansell and Kakwa areas. The following table summarizes capital expenditures for the year.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2009**	2008	**2009**	2008
Land	**1,150**	730	**4,115**	2,106
Seismic	**644**	1,036	**1,470**	3,300
Drilling and Completions	**27,449**	15,786	**66,926**	114,302
Production Equipment, Facilities & Pipelines	**4,993**	4,915	**11,417**	19,583
Office Equipment	**13**	-	**153**	33
Total Capital Expenditures	**34,249**	22,467	**84,081**	139,324
Drilling Royalty Credit	**(7,942)**	-	**(11,342)**	-
Net Capital Expenditures	**26,307**	22,467	**72,739**	139,324

During the year, 24 gross (22.5 net) vertical and 5 gross (3.7 net) horizontal gas wells were drilled with 35 gross (32.5 net) new gas zones brought on production. Total capital per net well was $3.2 million in 2009 (prior to DRC), down from $3.4 million in 2008, despite the 5 horizontal wells which increase the average well cost.

Reserves

New reserves were again found and developed "by the drill bit" with the following table illustrating the change in reserve volumes and Net Present Value ("NPV") of future cash flow, discounted at 5%, before income tax using forecast pricing.

	As at December 31			
	2009	2008	% Change	% Change, debt adjusted per unit†
Reserves				
BCFe				
Proved Producing	**591.4**	599.8	*-1%*	*5%*
Total Proved	**893.1**	762.9	*17%*	*8%*
Proved + Probable Additional	**1,199.3**	998.3	*20%*	*28%*
Net Present Value ($million)				
Discounted at 5%				
Proved Producing	**$2,389**	$2,736	*-13%*	*-20%*
Total Proved	**$3,344**	$3,267	*2%*	*-4%*

Proved + Probable Additional	**$4,295**	$4,077	*5%*	*-1%*

†Per unit reserves are adjusted for changes in net debt by converting debt to equity using the Dec 31 unit price of $9.90 for 2008 and $14.06 for 2009. Net Present Values are adjusted for debt by subtracting net debt from the value prior to calculating per unit amounts.
Note: Based on the Paddock Lindstrom & Associates report effective December 31, 2009. The Paddock Lindstrom and Associates Ltd. price forecast is available at www.padlin.com. For more information on Peyto's reserves, refer to the Press Release dated February 10, 2010 announcing the 2009 Year End Reserve Report which is available on the website at www.peyto.com. The complete statement of reserves data and required reporting in compliance with NI 51-101 will be included in Peyto's Annual Information Form to be released in March 2010.

Value Creation/Reconciliation

In order to measure the success of the 2009 investments, it is necessary to quantify the amount of incremental value created during the year and compare that to the amount of capital invested. This exercise is undertaken to ensure the best use of the unitholders' capital on a go forward basis. At Peyto's request, and for the benefit of unitholders, the independent engineers have run last year's evaluation with this year's price forecast to remove the change in value attributable to both commodity prices and changing royalties. This approach isolates the value created by the Peyto team from the value created (or lost) by those changes outside of their control. Since the capital investments in 2009 were funded from a combination of cash flow, debt and equity, it is necessary to know the change in debt and the change in units outstanding to see if the change in value is truly accretive.

At year end 2009, the forecasted net debt had decreased by $52.8 million to $439.9 million while the number of units outstanding had increased by 9.2 million units to 115.1 million units (including the Dec. 31, 2009 private placement of 196,420 units issued on January 6, 2010). The change in debt includes all of the capital expenditures, net of Drilling Royalty Credits earned, and the total fixed and performance based compensation paid out during the year.

Based on this reconciliation of changes in BT NPV, the Peyto team was able to create $390 million of Proved Producing, $1,375 million of Total Proven, and $1,968 million of Proved plus Probable Additional undiscounted reserve value, with $73 million of capital investment. The ratio of capital expenditures to value creation is what Peyto refers to as the NPV recycle ratio, which is simply the undiscounted value addition, resulting from the capital program, divided by the capital investment. For 2009, the Proved Producing NPV recycle ratio is 5.4, compared with 2.1 for 2008.

The following table breaks out the value created by Peyto's capital investments and reconciles the changes in debt adjusted NPV of future net revenues using forecast prices and costs as at December 31, 2009.

	Proved Producing			Total Proved			Proved + Probable Additional		
($millions) Discounted at	0%	5%	10%	0%	5%	10%	0%	5%	10%
Before Tax Net Present Value at Beginning of Year ($millions)									
Dec. 31, 2008 Evaluation using PLA Jan. 1, 2009 price forecast, less debt	**$4,781**	**$2,244**	**$1,332**	**$5,995**	**$2,775**	**$1,612**	**$8,069**	**$3,584**	**$2,037**
Debt Adjusted Per Unit Outstanding at Dec. 31, 2008 ($/unit)	$45.13	$21.18	$12.58	$56.60	$26.19	$15.22	$76.18	$33.84	$19.23
2009 sales (revenue less royalties and operating costs)	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**
Net Change due to price forecasts (using PLA Jan 1, 2010 price forecast)	**($729)**	**($390)**	**($275)**	**($934)**	**($500)**	**($349)**	**($1,213)**	**($626)**	**($428)**
Value Change due to discoveries (additions, extensions, transfers, revisions)	**$390**	**$322**	**$308**	**$1,375**	**$856**	**$650**	**$1,968**	**$1,124**	**$807**
Before Tax Net Present Value at End of Year ($millions)									
Dec. 31, 2009 Evaluation using PLA Jan. 1, 2010 price forecast, less debt	**$4,215**	**$1,949**	**$1,138**	**$6,210**	**$2,904**	**$1,687**	**$8,598**	**$3,856**	**$2,188**

Debt Adjusted Per Unit Outstanding at Dec. 31, 2009 ($/unit)	$36.62	$16.93	$9.89	$53.95	$25.23	$14.65	$74.69	$33.49	$19.01

Year over Year Change in Before Tax NPV/unit	**(19%)**	**(20%)**	**($21)**	**(5%)**	**(4%)**	**(4%)**	**(2%)**	**(1%)**	**(1%)**
Year over Year Change in Before Tax NPV/unit including Dist. ($1.47/unit)	**(16%)**	**(13%)**	**(10%)**	**(2%)**	**2%**	**6%**	**0%**	**3%**	**7%**

Performance Measures

There are a number of performance measures that are used in the oil and gas industry in an attempt to evaluate how profitably capital has been invested. Peyto believes that the value analysis presented above is the best determination of profitability as it compares the value of what was created relative to what was invested, or what is termed, the NPV recycle ratio. This is because the NPV of an oil and gas asset takes into consideration the reserves, the production forecast, the future royalties and operating costs, future capital and the current commodity price outlook. In 2009, the Proved Producing NPV recycle ratio was 5.4 times. This means for each dollar invested, the Peyto team was able to create 5.4 new dollars of Proved Producing reserve value. The average NPV Recycle Ratio over the last 5 years is 3.5 times for undiscounted future values or 2.2 times for future values discounted at 10%. The historic NPV recycle ratio is presented in the following table.

2009 Value Creation	**Dec 31, 2009**	Dec 31, 2008	Dec 31, 2007	Dec 31, 2006	Dec 31, 2005
NPV_0 Recycle Ratio					
Proved Producing	**5.4**	2.1	4.7	2.9	2.5
Total Proved	**18.9**	2.5	5.5	2.9	2.8
Proved + Probable Additional	**27.1**	2.2	3.8	3.8	3.2

- NPV_0 (net present value) recycle ratio is calculated by dividing the undiscounted NPV of reserves added in the year by the total capital cost for the period (eg. Proved Producing ($390/$72.7) = 5.4).

The following table highlights some additional annual performance ratios, to be used for comparative purposes, but it is cautioned that they are incomplete and on their own do not measure investment success.

Performance Ratios	**Proved Producing**	**Total Proved**	**Proved + Probable Additional**
Finding, Development and Acquisition Costs ($/MCFe)			
2009 FD&A Cost (including the change in future development capital "FDC")	$2.26	$1.73	$1.47
2008 FD&A (incl. change in FDC)	$2.88	$3.17	$3.88
2007 FD&A (incl. change in FDC)	$2.11	$1.57	$1.56
3 year average (2007-2009)	$2.42	$2.16	$2.30
2009 Change in future development capital ($ millions)		$223	$282
Recycle Ratio (incl. change in FDC)			
Using 2009 field netback before hedging of $4.04/MCFe	1.8	2.3	2.7
Reserve Life Index (years)			
Q4 2009 average production – 114.8 MMCFe/d	14	21	29
Distribution Life Index (years)			
Q4 2009 annualized - $41.4 million	25	38	52
Reserve Replacement Ratio			
2009 production – 40.5 BCFe	0.8	4.2	6.0

- FD&A (finding, development and acquisition) costs are used as a measure of capital efficiency and are calculated by dividing the capital costs for the period, including the change in undiscounted future development capital ("FDC"), by the change in the reserves, incorporating revisions and production, for the same period (eg. Total Proved ($72.7+$223.2)/(893.1-762.9+40.5) = $1.73).

- The Recycle Ratio is calculated by dividing the field netback per MCFe, before hedging, by the FD&A costs for the period (eg. Proved Producing (($5.60-$1.56)/$2.26=1.8). The recycle ratio is comparing the netback from existing reserves to the cost of finding new reserves and may not accurately indicate investment success unless the replacement reserves are of equivalent quality as the produced reserves.
- The reserve life index is calculated by dividing the reserves (in MMCFe) in each category by the annualized average production rate in MMCFe/year (eg. Proved Producing 591,438/(114.8x365) = 14).
- The distribution life index is calculated by dividing the debt adjusted undiscounted NPV by the Q4 annualized distribution (eg. Proved Producing ($4,655-$439.9 million)/(41.4x4) million/year = 25 years).
- The reserve replacement ratio is determined by dividing the yearly change in reserves before production by the actual annual production for the year (eg. Total Proved ((148,857-127,156+6,745)/6,745) = 4.2).

Finding, development and acquisition costs improved in 2009 as service cost reductions and increased recoveries combined to reduce the Proved Producing FD&A by 22% to $2.26/MCFe ($13.58/boe). The application of horizontal wells with multi-stage fracture stimulations to three of Peyto's Deep Basin formations resulted in the recognition of increased undeveloped reserves in both the Total Proved and Proved plus Probable Additional categories. The increase in undeveloped reserves served to reduce FD&A costs for Total Proved and P+P to $1.73/MCFe ($10.41/boe) and $1.47/MCFe ($8.80/boe) respectively (inclusive of changes in future development capital).

The cost to replace the Proved Producing reserves of $2.26/MCFe was 56% of the achieved 2009 field netback, before hedging effects, of $4.04/MCFe. This results in a recycle ratio of 1.8 times for Proved Producing, 2.3 times for Total Proved and 2.7 times for Proved plus Probable Additional.

The Total Proved and P+P reserve life index increased by 24% and 27% respectively to 21 and 29 years, primarily driven by the increases in undeveloped reserves. These increases occurred despite little change in Proved Producing reserve life and illustrates why Peyto believes the most accurate way to evaluate current reserve life is by dividing Proved Producing reserves by the most current average production rate. Using this method, Peyto's Proved Producing reserve life, based the on annualized Q4 2009 production rate, is 14 years. In Peyto's opinion, and for comparative purposes, the Proved Producing reserve life provides the best measure of sustainability.

The following table highlights the Trust's historical Reserve and Distribution Life Index.

	2003	2004	2005	2006	2007	2008	2009
PP RLI	10	9	11	12	13	14	14
PP DLI	14	17	22	23	24	25	25

Quarterly Review

Capital expenditures for the fourth quarter 2009 increased to $34.2 million (before $7.9 million in drilling royalty credits) up 52% from Q4 2008 and up 7% from Q3 2009 as the Trust continued to actively develop its Deep Basin resource plays. Drilling and completions accounted for $27.4 million while production equipment, pipelines and facilities accounted for $5.0 million. Land and seismic made up the balance of the capital expenditures at $1.8 million.

Daily production for Q4 2009 increased from 107 mmcfe/d in the previous quarter to 115 mmcfe/d, but was down from 121 mmcfe/d a year ago. Natural gas production of 95.5 mmcf/d and oil and natural gas liquids production of 3,222 bbls/d combined for the quarter over quarter increase. Natural gas prices, before hedging effects, also increased quarter over quarter from $3.31/mcf to $4.79/mcf, but were down from $7.30/mcf a year ago. Peyto's marketing strategy of layering in forward sales contributed for a gain of $1.38/mcf in the quarter, resulting in a realized gas price $6.17/mcf. Oil and natural gas liquids price averaged $60.77/bbl. Total revenue was down 19% from the previous year due primarily to the price of natural gas.

Fourth quarter 2009 operating costs of $0.38/mcfe were 13% lower than Q4 2008 primarily due to the optimization of methanol consumption in field operations. Transportation costs increased from $0.10/mcfe in Q4 2008 to $0.11/mcfe in Q4 2009 due to an increase in the pipeline tariffs. Royalties were 12% of sales, before hedging, in Q4 2009, effectively the same as in Q4 2008. Net of hedging effects, royalties were reduced to 10% of sales or $0.71/mcfe. G&A of $0.15/mcfe and interest expense of $0.44/mcfe combined with royalty, operating and transportation costs for a total cash cost of $1.79/mcfe, leaving a cash netback of $5.05/mcfe. This cash netback translates into a 74% operating margin.

Marketing

Peyto's marketing strategy of smoothing out short term fluctuations in the price of natural gas through future sales was again successful in 2009. A total realized hedging gain of $63.0 million for the year was the largest in the Trust's history. Since 2003, when the Trust began the practice of selling up to 50% of its total natural gas production for periods up to 24 months in advance, the cumulative realized gain has been $127 million. It is not expected that gains will always be realized. Over the long run, Peyto expects to break even on forward sales since this approach of layering in future sales will show hedging losses when short term prices climb and hedging gains when short term prices fall. In order to minimize counterparty risk, these marketing contracts are executed with financial institutions that are also members of Peyto's loan syndicate.

Details of the individual contracts are available in Management's Discussion and Analysis ("MD&A"). As of December 31, 2009, the Trust had committed to the future sale of 23,380,000 gigajoules (GJ) of natural gas at an average price of $6.03/GJ or $7.05/mcf. Had these contracts been closed on December 31, 2009, the Trust would have realized a gain in the amount of $9.9 million.

Activity Update

To date in 2010, Peyto has drilled 4 vertical and 5 horizontal wells (8.6 net or 96% average working interest). Currently there are two vertical rigs and two horizontal rigs active in the Trust's Deep Basin core areas. Horizontal wells are contributing 11% of the 125 mmcfe/d of current production and are expected to make up over 25% of the Trust's total production by the end of 2010. Minor infrastructure expansions in the form of pipeline looping and compressor installations are ongoing in order to minimize the backout effect of new production on existing volumes.

Spot natural gas prices in Alberta (AECO C Daily) dropped from $5.25/GJ in mid February 2010 to $4.25/GJ currently on expectations of an early end to winter and a ramping up of North American gas drilling. Peyto will remain flexible with respect to changes in natural gas prices and adjust the pace of its capital program accordingly.

Corporate Conversion

Peyto met with its advisors in 2009 and determined that, barring any unforeseen legislative changes and pending unitholder and regulatory approval, the conversion of the Trust into a corporate form will likely occur on December 31, 2010. The new corporate structure will continue to afford Peyto the ability to return profits from the success of the business to shareholders in the form of dividends. For the remainder of 2010, the Trust plans on maintaining distributions at $0.12/unit/month.

2010 Outlook

The future landscape for Peyto has changed significantly since this time last year. The world economies have stabilized and begun to recover with the emerging economies leading the way; especially in their demand for hydrocarbons. Here in North America, the glut of shale gas has literally been burned off by a cold winter, contributing to the recovery in natural gas prices. Evidence of the true supply cost of shale gas continues to emerge as does Western Canada's ability to compete. Meanwhile, Peyto's future looks even more encouraging with an increased inventory of resource opportunities, an enviable cost structure and a proven track record of profitable investing.

The trust anticipates, with its expected capital program of $175 to $200 million, that production growth will be achieved this year and strong total returns delivered to unitholders. Capital expenditures will continue to be funded from a combination of cashflow after distributions, working capital, equity, and bank lines.

Conference Call and Webcast

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2009 fourth quarter and full year financial results on Thursday, March 11, 2010, at 9:00 a.m. Mountain Standard Time (MST), or 11:00 a.m. Eastern Standard Time (EST). To participate, please call 1-416-340-8018 (Toronto area) or 1- 866-223-7781 for all other participants. The conference call will also be available on replay by calling 1-416-695-5800 (Toronto area) or 1-800-408-3053 for all other parties, using passcode 1504448. The replay will be made available at 11:00 a.m. MST or 1:00 p.m. EST Thursday, March 11, 2009 until midnight EST on Thursday, March 18th, 2009. The live conference call can also be accessed through the internet at http://events.digitalmedia.telus.com/peyto/031110/testframeset.php. After this time the conference call will be archived on the Peyto Energy Trust website at www.peyto.com.

Management's Discussion and Analysis

A copy of the fourth quarter report to Unitholders, including the Management's Discussion and Analysis, and audited financial statements and related notes is available at http://www.peyto.com/news/Q42009MDandA.pdf and will be filed at SEDAR, www.sedar.com , at a later date.

Annual General Meeting

The Trust's Annual General Meeting of Unitholders is scheduled for 3:00 p.m. on Wednesday, May 19, 2010 at Livingston Place Conference Centre, +15 level, 222-3rd Avenue SW, Calgary, Alberta.

Unitholders are encouraged to visit the Peyto website at www.peyto.com where there is a wealth of information designed to inform and educate investors. A monthly President's Report can also be found on the website which follows the progress of the capital program and the ensuing production growth.

Darren Gee
President and CEO
March 10, 2010

Certain information set forth in this document and Management's Discussion and Analysis, including management's assessment of Peyto'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 Peyto will derive therefrom.

Peyto Energy Trust

Consolidated Balance Sheets

($000)

	December 31, 2009	December 31, 2008
Assets		
Current		
Accounts receivable *(Note 5)*	**58,305**	65,662
Due from private placement *(Note 9)*	**2,728**	-
Financial derivative instruments *(Note 15)*	**8,683**	27,788
Prepaid expenses	**3,787**	3,367
	73,503	96,817
Financial derivative instruments *(Note 15)*	**1,253**	2,458
Prepaid capital	**955**	3,069
Property, plant and equipment *(Note 6)*	**1,178,402**	1,177,902
	1,180,610	1,183,429
	1,254,113	1,280,246
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**55,890**	48,854
Cash distributions payable *(Note 10)*	**13,790**	15,888
Provision for future performance based compensation *(Note 13)*	**2,001**	-
	71,681	64,742
Long-term debt *(Note 7)*	**435,000**	500,000
Provision for future performance based compensation *(Note 13)*	**1,041**	-
Asset retirement obligations *(Note 8)*	**10,487**	9,479
Future income taxes *(Note 14)*	**123,421**	155,308
	569,949	664,787
Unitholders' equity		
Unitholders' capital *(Note 9)*	**500,407**	410,233
Units to be issued *(Note 9)*	**2,728**	-
Accumulated earnings *(Note 10)*	**99,749**	110,238
Accumulated other comprehensive income	**9,599**	30,246
	109,348	140,484
	612,483	550,717
	1,254,113	1,280,246

See accompanying notes

On behalf of the Board:

(signed) *“Michael MacBean”* (signed) *“Darren Gee”*

Director Director

Peyto Energy Trust

Consolidated Statements of Earnings

($000 except per unit amounts)

For the years ended December 31,

	2009	2008
Revenue		
Oil and gas sales	**210,530**	428,047
Realized gain (loss) on hedges *(Note 15)*	**62,987**	(9,161)
Royalties	**(25,671)**	(79,821)
Petroleum and natural gas sales, net	**247,846**	339,065
Expenses		
Operating *(Note 11)*	**16,736**	19,042
Transportation	**4,541**	4,604
General and administrative*(Note 12)*	**7,292**	6,655
Performance based compensation *(Note 13)*	**5,080**	-
Future performance based compensation *(Note 13)*	**3,042**	(269)
Interest on long term debt	**16,527**	21,857
Depletion, depreciation and accretion *(Notes 6 and 8)*	**73,298**	75,668
	126,516	127,557
Earnings before taxes	**121,330**	211,508
Taxes		
Future income tax (recovery) expense *(Note 14)*	**(31,444)**	32,111
Earnings for the year	**152,774**	179,397
Earnings per unit *(Note 9)*		
Basic and diluted	**1.38**	1.69

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Comprehensive Income

($000)

For the years ended December 31,

	2009	2008
Earnings for the year	**152,774**	179,397
Other comprehensive income (loss)		
Change in unrealized gain (loss) on cash flow hedges	**42,340**	15,966
Realized (gain) loss on cash flow hedges	**(62,987)**	9,161
Comprehensive Income	**132,127**	204,524

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Accumulated Earnings and Accumulated Other Comprehensive Income

($000)

For the years ended December 31,

	2009	2008
Accumulated earnings, beginning of year	**110,238**	117,572
Earnings for the year	**152,774**	179,397
Distributions *(Note 10)*	**(163,263)**	(186,731)
Accumulated earnings, end of year	**99,749**	110,238
Accumulated other comprehensive income, beginning of year	**30,246**	5,119
Other comprehensive income (loss)	**(20,647)**	25,127
Accumulated other comprehensive income, end of year	**9,599**	30,246

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Cash Flows

($000)

For the years ended December 31,

	2009	2008
	$	$
Cash provided by (used in)		
Operating Activities		
Earnings for the year	**152,774**	179,397
Items not requiring cash:		
Future income tax (recovery) expense	**(31,444)**	32,111
Depletion, depreciation and accretion	**73,298**	75,668
Expenditures on site restoration and reclamation *(Note 8)*	**(51)**	-
Change in non-cash working capital related to operating activities *(Note 17)*	**4,111**	(39,055)
	198,688	248,121
Financing Activities		
Issue of trust units	**94,500**	3,932
Issuance costs	**(5,106)**	-
Cash distributions paid	**(163,263)**	(186,731)
Increase (decrease) in bank debt	**(65,000)**	70,000
Change in non-cash working capital related to financing activities *(Note 17)*	**(2,098)**	1,088
	(140,967)	(111,711)
Investing Activities		
Additions to property, plant and equipment	**(70,624)**	(142,393)
Change in non-cash working capital related to investing activities *(Note 17)*	**12,903**	(14,564)
	(57,721)	(156,957)
Net increase (decrease) in cash	**-**	(20,547)
Cash, beginning of year	**-**	20,547
Cash, end of year	**-**	-

See accompanying notes

Peyto Energy Trust

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

1. Nature of Operations

Peyto Energy Trust (the "Trust" or "Peyto") is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The beneficiaries of the Trust are the holders of the Trust units. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust and are entitled to one vote for each Trust unit held at unitholder meetings.

The Trust units trade on the TSX under the symbol "PEY.UN". The Trust's principal business activity is the exploration for, development and production of petroleum and natural gas in western Canada.

2. Summary of Significant Accounting Policies

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

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

Joint operations
The Trust conducts a portion of its petroleum and natural gas exploration, development and production activities jointly with others and, accordingly, these consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Property, plant and equipment
The Trust follows the full cost method of accounting for its petroleum and natural gas properties. All costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities. All other general and administrative costs are expensed as incurred.

The Trust evaluates its petroleum and natural gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties ("ceiling test"). The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves plus the cost of unproved properties, less impairment, exceed the carrying value of the oil and gas assets. If the carrying value of the petroleum and natural gas properties is not determined to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves plus the cost of unproved properties, less impairment. The discounted cash flows are estimated using the future product prices and costs and are discounted using a risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

All costs of acquisition, exploration and development of petroleum and natural gas reserves (net of salvage value) and estimated costs of future development of proved undeveloped reserves are depleted and depreciated using the unit of production method based on estimated gross proved reserves as determined by independent engineers. For purposes of the depletion and depreciation calculation, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Costs of unproved properties are initially excluded from petroleum and natural gas properties for the purpose of calculating depletion. When proved reserves are assigned to the property or it is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Depreciation of gas plants and related facilities is calculated on a straight-line basis over a 20-year term. Office furniture and equipment are depreciated over their estimated useful lives at declining balance rates between 20% and 30%.

Asset retirement obligations

The Trust records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. 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. Actual costs incurred upon settlement of the obligations are charged against the liability.

Hedging

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. The Trust does not enter into derivative financial instruments for trading or speculative purposes. All derivative financial instruments are initiated within the guidelines of the Trust's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Trust enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into natural gas fixed price contracts, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract. For financial derivative contracts settling in future periods, a financial asset or liability is recognized in the balance sheet and measured at fair value, with changes in fair value recognized in other comprehensive income.

Revenue recognition

Petroleum and natural gas sales are recognized as revenue when title passes to purchasers, normally at pipeline delivery point for natural gas and at the wellhead for crude oil.

Measurement uncertainty

The timely preparation of the consolidated financial statements in conformity with Canadian generally accepted accounting principles requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of gross proved reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the consolidated financial statements of future periods could be material.

The amount of compensation expense accrued for future performance-based compensation arrangements are subject to management’s best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Trust and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Future income taxes
The Trust follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in earnings in the period that the change occurs.

Financial Instruments
All financial instruments must initially be recognized at fair value on the consolidated balance sheet. The Trust has classified each financial instrument into the following categories: "held for trading"; "loans & receivables"; and "other financial liabilities". Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method. The Trust has made the following classifications:

Financial Assets & Liabilities	**Category**
Cash	Held for trading
Accounts Receivable	Loans & receivables
Due from Private Placement	Loans & receivables
Accounts Payable and Accrued Liabilities	Other Liabilities
Provision for Future Performance Based Compensation	Other Liabilities
Distributions Payable	Other Liabilities
Long Term Debt	Other Liabilities
Financial Derivative Instruments	Held for trading

Derivative Instruments and Risk Management
Derivative instruments are utilized by the Trust to manage market risk against volatility in commodity prices. The Trust's policy is not to utilize derivative instruments for speculative purposes. The Trust has chosen to designate its existing derivative instruments as cash flow hedges. The Trust assesses, on an ongoing basis, whether the derivatives that are used as cash flow hedges are highly effective in offsetting changes in cash flows of hedged items. All derivative instruments are recorded on the balance sheet at their fair value. The effective portion of the gains and losses is recorded in other comprehensive income until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the consolidated statement of earnings, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Any hedge ineffectiveness is immediately recognized in earnings. The fair values of forward contracts are based on forward market prices.

Embedded Derivatives
An embedded derivative is a component of a contract that causes some of the cash flows of the combined instrument to vary in a way similar to a stand-alone derivative. This causes some or all of the cash flows that otherwise would be required by the contract to be modified according to a specified variable, such as interest rate, financial instrument price, commodity price, foreign exchange rate, a credit rating or credit index, or other variables to be treated as a financial derivative. The Trust has no contracts containing embedded derivatives.

3. Changes in Accounting Policies

Goodwill and Intangible Assets
On January 1, 2009, the Trust retrospectively adopted the Canadian Institute of Chartered Accountants (CICA) Section 3064, Goodwill and Intangible Assets issued by the Accounting Standards Board ("AcSB"). This section clarifies the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Adoption of this standard did not have an impact the Trust's results of operations or financial position.

Business Combinations
On January 1, 2009, the Trust prospectively adopted CICA Section 1582, Business Combinations issued by the AcSB. This section establishes principles and requirements of the acquisition method for business combinations and related disclosures. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Consolidated Financial Statements and Non-Controlling Interests
On January 1, 2009, the Trust adopted CICA Sections 1601, Consolidated Financial Statements, and 1602, Non-Controlling Interests issued by the AcSB. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for non-controlling interests in consolidated financial statements subsequent to a business combination. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities
Effective January 20, 2009, the Trust adopted the CICA Emerging Issues Committee (EIC) Abstract No.173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities (EIC 173). EIC 173 clarifies how an entity's own credit risk and that of the relevant counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Financial Instruments – Disclosures
In May 2009, the CICA amended Section 3862, Financial Instruments – Disclosures, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

Financial Instruments – Recognition and Measurement
In July 2009, the CICA amended Section 3855, Financial Instruments – Recognition and Measurement, to prohibit the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured. Amendments to this section also include a revised definition of "loans and receivables" and, provided that certain conditions have been met, permits reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. These amendments are effective for the Trust on December 31, 2009.

4. Pending Accounting Pronouncements

International Financial Reporting Standards ("IFRS")
In January 2006, the CICA Accounting Standards Board ("ASCB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by 2011.

On February 13, 2008, The ASCB confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-orientated enterprises.

5. Accounts Receivable

($000)	**2009**	2008
Accounts receivable – general	**51,150**	58,394
Accounts receivable – income taxes	**7,155**	7,268
	58,305	65,662

Canada Revenue Agency ("CRA") has conducted an audit of restructuring costs claimed as a result of the Trust conversion in 2003 that has resulted in the reclassification of $41.0 million dollars in employment related costs as eligible capital. In October, 2008, the Trust received a notice of reassessment from the CRA and paid an amount of $7.2 million related to this audit. Based upon consultation with legal counsel, Management's view is that CRA's position has no merit. A notice of appeal was filed May 19, 2009 and the appeal has been denied. Examinations for discovery are being scheduled.

6. Property, Plant and Equipment

($000)	**2009**	2008
Property, plant and equipment	**1,624,655**	1,551,789
Accumulated depletion and depreciation	**(446,253)**	(373,887)
	1,178,402	1,177,902

At December 31, 2009 costs of $26.6 million (December 31, 2008 - $36.8 million) related to undeveloped land have been excluded from the depletion and depreciation calculation.

The Trust performed a ceiling test calculation at December 31, 2009 resulting in the undiscounted cash flows from proved reserves plus the cost of unproved properties, less impairment, exceeding the carrying value of petroleum and natural gas assets. The impairment test was calculated at December 31, 2009 using the following independent engineering consultant's forecasted prices:

	2010	**2011**	**2012**	**2013**	**2014**	**Thereafter (1)**
Edmonton Ref Price ($CDN/bbl)	84.21	86.84	89.47	94.74	100.00	+2.0%
CDN/US Exchange rate	0.95	0.95	0.95	0.95	0.95	0.95
AECO ($CDN/mmbtu)	5.82	6.29	6.77	7.28	7.80	+2.3%

(1) Percentage change for the Edmonton Ref Price and the AECO Price of 2.0% and 2.3% respectively, represents the average change in future prices each year after 2014 to the end of the reserve life.

7. Long-Term Debt

The Trust has a syndicated $550 million extendible revolving credit facility with a stated term date of April 30, 2010. The facility is made up of a $20 million working capital sub-tranche and a $530 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 plus 1.50% to prime plus 3.00% for debt to earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) 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. The Trust is in compliance with all debt covenants. The average borrowing rate for 2009 was 3.5% (2008 – 4.8%).

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 $10.5 million as at December 31, 2009 (2008 - $9.5 million) based on a total future liability of $36.0 million (2008 - $34.2 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 obligations.

The following table reconciles the change in asset retirement obligations:

($000)	**2009**	2008
Balance, December 31, 2008	**9,479**	6,766
Increase in liabilities relating to investing activities	**392**	1,697
Settlement of reclamation liabilities during the year	**(51)**	-
Accretion expense	**667**	1,016
Balance, December 31, 2009	**10,487**	9,479

9. Unitholders' Capital

Authorized: Unlimited number of voting trust units

Issued and Outstanding

Trust Units (no par value) ($000)	Number of Units	Amount
Balance, December 31, 2007	**105,712,364**	**406,301**
Trust units issued by private placement	207,830	3,932
Balance, December 31, 2008	**105,920,194**	**410,233**
Trust units issued by private placement	-	-
Trust units issued	9,000,000	94,500
Trust unit issuance costs (net of tax)	-	(4,326)
Balance, December 31, 2009	**114,920,194**	**500,407**

On June 26, 2009, Peyto closed an offering of 9,000,000 trust units at a price of $10.50 per trust unit, receiving net proceeds of $89.4 million.

Units to be Issued
On December 31, 2009 the Trust completed a private placement of 196,420 trust units to employees and consultants for net proceeds of $2,728,274 (priced using the weighted average price for the last 5 trading days of December). These trust units were issued on January 6, 2010.

Per Unit Amounts
Earnings per unit have been calculated based upon the weighted average number of units outstanding during the year of 110,555,810 (2008 - 105,876,470). There are no dilutive instruments outstanding.

Redemption of Units
The Trust Units are redeemable at any time on demand by the holders thereof. Upon receipt of proper notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit equal to the lesser of:

(a) 90% of the market price of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and

(b) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

Comprehensive Income
Comprehensive income consists of earnings and other comprehensive income ("OCI"). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge. "Accumulated other comprehensive income" is a equity category comprised of the cumulative amounts of OCI.

10. Accumulated Cash Distributions

During the year, the Trust paid distributions to the unitholders in the aggregate amount of $163.3 million (2008 - $186.7 million total) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit(1)
January 2009	January 31, 2009	February 13, 2009	$0.15
February 2009	February 29, 2009	March 13, 2009	$0.12
March 2009	March 31, 2009	April 15, 2009	$0.12
April 2009	April 30, 2009	May 15, 2009	$0.12
May 2009	May 31, 2009	June 15, 2009	$0.12
June 2009	June 30, 2009	July 15, 2009	$0.12
July 2009	July 31, 2009	August 14, 2009	$0.12

August 2009	August 31, 2009	September 15, 2009	$0.12
September 2009	September 30, 2009	October 15, 2009	$0.12
October 2009	October 31, 2009	November 14, 2009	$0.12
November 2009	November 30, 2009	December 15, 2009	$0.12
December 2009	December 31, 2009	January 15, 2010	$0.12

(1) Distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

Accumulated Earnings and Distributions

($000)	**2009**	2008
Accumulated earnings, beginning of year	**919,435**	740,038
Earnings for the year	**152,774**	179,397
Total accumulated earnings	**1,072,209**	919,435
Total accumulated distributions	**(972,460)**	(809,197)
Accumulated earnings, end of year	**99,749**	110,238

11. 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.

($000)	**2009**	2008
Field expenses	**27,487**	30,391
Processing and gathering income	**(10,751)**	(11,349)
Total Operating expenses	**16,736**	19,042

12. General and Administrative Expenses

General and administrative expenses are reduced by operating and capital overhead recoveries from operated properties.

($000)	**2009**	2008
General and Administrative expenses	**9,797**	10,227
Overhead recoveries	**(2,505)**	(3,572)
Net General and administrative expenses	**7,292**	6,655

13. Performance Based Compensation

The Trust awards performance based compensation to employees and key consultants annually. The performance based compensation is comprised of reserve and market value based components.

Reserve Based Component

The reserves value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity, distributions, general and administrative costs and interest, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%.

($millions except unit values)	2009	2008	Change
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2010 price forecast	**1,379.0**	1,534.0	
Net debt before performance based compensation	**(437.5)**	(492.6)	
2009 distributions, general and administration and interest expense	**187.1**		
Net value	**1,128.6**	1,041.4	**87.2**
Equity adjustment factor*			15%
Equity adjusted increase in value			**13.1**
2009 reserve value based compensation @ 4%			**0.5**

*Equity adjustment factor is calculated as the percent increase in reserve value per unit divided by the total percent increase in reserve value

Market Based Component

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 6% 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. Compensation 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. The 2009 market based component was based on 1.4 million vested rights at an average grant price of $17.46, average cumulative distributions of $4.91; 0.5 million vested rights at an average grant price of $9.53, average cumulative distributions of $1.47 and the five day weighted average closing price of $13.89 (2008 – 1.2 million rights, average grant price of $24.94, average cumulative distributions of $5. 10 per unit and five day weighted average closing price of $9.53).

The total amount expensed under these plans was as follows:

($000)	2009	2008
Market based compensation	**4,540**	**-**
Reserve value based compensation	**540**	**-**
Total	**5,080**	**-**

For the future market based component, compensation costs as at December 31, 2009 related to 1.5 million non-vested rights with an average grant price of $16.53 and 1.0 million non-vested rights with an average grant price of $9.55 were $3.0 million (2008 - 3.1 million non-vested rights with an average grant price of $17.04 were $nil).

14. Future Income Taxes

($000)	**2009**	2008
Earnings before income taxes	**121,330**	211,508
Statutory income tax rate	**29.00%**	32.50%
Expected income taxes	**35,186**	68,740
Increase (decrease) in income taxes from:		
Corporate income tax rate change	**(25,277)**	9,338
Income attributed to the trust	**(40,244)**	(45,516)
Change in valuation allowance for share issue costs	**(1,040)**	(480)
Other	**(69)**	29
Future income tax expense (recovery)	**(31,444)**	32,111
Differences between tax base and reported amounts for depreciable assets	**126,746**	157,962
Financial derivative asset	**337**	
Share issuance costs	**(781)**	-
Future performance based bonuses	**(260)**	-
Provision for asset retirement obligation	**(2,621)**	(2,654)
Future income taxes	**123,421**	155,308

At December 31, 2009 the Trust has tax pools of approximately $676.1 million (December 31, 2008 - $653.8 million) available for deduction against future income. The Trust has approximately $6.0 million (December 31, 2008 - $1.4 million) in unrecognized future income tax assets and approximately $nil in loss carryforwards (December 31, 2008 - $1.4 million) available to reduce future taxable income.

15. Financial Instruments and Risk Management

Financial Instrument Classification and Measurement

Financial instruments of the Trust carried on the Consolidated Balance Sheet are carried at amortized cost with the exception of cash and cash equivalents and financial derivative instruments, specifically fixed price contracts, which are carried at fair value. There are no significant differences between the carrying value of financial instruments and their estimated fair values as at December 31, 2009.

The fair value of the Trust's cash and cash equivalents and financial derivative instruments are quoted in active markets. The Trust classifies the fair value of these transactions according to the following hierarchy.

- *Level 1* – quoted prices in active markets for identical financial instruments.
- *Level 2* – quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant and significant value drivers are observable in active markets.
- *Level 3* – valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Trust's cash and cash equivalents and financial derivative instruments have been assessed on the fair value hierarchy described above and classified as Level 1.

Fair Values of Financial Assets and Liabilities

The Trust's financial instruments include cash, accounts receivable, financial derivative instruments, due from private placement, current liabilities (excluding future income tax), provision for future performance based compensation and long term debt. At December 31, 2009, the carrying value of cash and cash equivalents and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities (excluding future income tax) and provision for future performance based compensation approximate their fair value due to their short term nature. The carrying value of the long term debt approximates its fair value due to the floating rate of interest charged under the credit facility.

Market Risk

Market risk is the risk that changes in market prices will affect the Trust's earnings or the value of its financial instruments. Market risk is comprised of commodity price risk and interest rate risk. The objective of market risk management is to manage and control exposures within acceptable limits, while maximizing returns. The Trust's objectives, processes and policies for managing market risks have not changed from the previous year.

Commodity Price Risk Management

The Trust is a party to certain 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 transactions and the underlying basis of the instruments correlate highly with the Trust's exposure. A summary of contracts outstanding in respect of the hedging activities at December 31, 2009 is as follows:

Description	Notional [(1)]	Term	Effective Rate	Fair Value Level	Asset (Liability) as at December 31, 2009	Asset (Liability) as at December 31, 2008
Natural gas financial swaps - AECO	23.38 GJ [(2)]	2010- 2012	$6.03/GJ	Level 1	9,936	30,246

[(1)] Notional values as at December 31, 2009 [(2)] Millions of gigajoules

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1 , 2009 to March 31, 2010	Fixed Price	5,000 GJ	$7.65/GJ
April 1 , 2009 to March 31, 2010	Fixed Price	5,000 GJ	$6.90/GJ
November 1, 2009 to March 31, 2010	Fixed Price	5,000 GJ	$8.39/GJ
November 1, 2009 to March 31, 2010	Fixed Price	5,000 GJ	$8.35/GJ
November 1, 2009 to March 31, 2010	Fixed price	5,000 GJ	$5.25/GJ
November 1, 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.20/GJ
November 1, 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.00/GJ
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	$6.20/GJ
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	$5.81/GJ
April 1, 2010 to October 31, 2010	Fixed price	5,000 GJ	$6.10/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.28/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.29/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.555/GJ
April 1, 2010 to March 31, 2012	Fixed price	5,000 GJ	$5.67/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$8.91/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$9.15/GJ
April 1, 2011 to March 31, 2012	Fixed price	5,000 GJ	$6.20/GJ

As at December 31, 2009, the Trust had committed to the future sale of 23,380,000 gigajoules (GJ) of natural gas at an average price of $6.03 per GJ or $7.05 per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on December 31, 2009, the Trust would have realized a gain in the amount of $9.9 million. If the AECO gas price on December 31, 2009 were to increase by $1/GJ, the unrealized gain on these closed contracts would change by approximately $23.4 million. An opposite change in commodity prices rates will result in an opposite impact on earnings which would have been reflected in the other comprehensive income of the Trust.

Subsequent to December 31, 2009 the Trust entered into the following contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1, 2010 to October 31, 2010	Fixed price	5,000 GJ	$5.50/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.70/GJ
April 1, 2010 to March 31, 2012	Fixed price	5,000 GJ	$5.82/GJ

Interest rate risk
The Trust is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Trust has not entered into any agreements to manage this risk. If interest rates applicable to floating rate debt were to have increased by 100 bps (1%) it is estimated that the Trust's net income for the year ended December 31, 2009 would decrease by $4.7 million. An opposite change in interest rates will result in an opposite impact on earnings.

Credit Risk
A substantial portion of the Trust's accounts receivable is with petroleum and natural gas marketing entities.

Industry standard dictates that commodity sales are settled on the 25th day of the month following the month of production. The Trust generally extends unsecured credit to these companies, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Trust's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Trust has not previously experienced any material credit losses on the collection of accounts receivable. Of the Trust's revenue for the year ended December 31, 2009, approximately 55% was received from the same three companies (21%, 20%, 14%, respectively) (December 31, 2008 – 90%, four companies (33%, 30%, 17% and 10%, respectively). The Trust had no significant individual accounts receivable at December 31, 2009 (December 31, 2008 – 35%, three companies (15%, 10%, 10%, respectively)). The maximum exposure to credit risk is represented by the carrying amount on the consolidated balance sheet. There are no material financial assets that the Trust considers past due and no accounts have been written off.

The Trust may be exposed to certain losses in the event of non-performance by counter-parties to commodity price contracts. The Trust mitigates this risk by entering into transactions with counter-parties that have investment grade credit ratings.

Counterparties to financial instruments expose the Trust to credit losses in the event of non-performance. Counterparties for derivative instrument transactions are limited to high credit quality financial institutions, which are all members of our syndicated credit facility.

The Trust assesses quarterly if there should be any impairment of financial assets. At December 31, 2009, there was no impairment of any of the financial assets of the Trust.

Liquidity Risk
Liquidity risk includes the risk that, as a result of operational liquidity requirements:

- The Trust will not have sufficient funds to settle a transaction on the due date;
- The Trust will be forced to sell financial assets at a value which is less than what they are worth; or
- The Trust may be unable to settle or recover a financial asset at all.

The Trust's operating cash requirements, including amounts projected to complete our existing capital expenditure program, are continuously monitored and adjusted as input variables change. These variables include, but are not limited to, available bank lines, oil and natural gas production from existing wells, results from new wells drilled, commodity prices, cost overruns on capital projects and changes to government regulations relating to prices, taxes, royalties, land tenure, allowable production and availability of markets. As these variables change, liquidity risks may necessitate the need for the Trust to conduct equity issues or obtain project debt financing. The Trust also mitigates liquidity risk by maintaining an insurance program to minimize exposure to some losses.

The following are the contractual maturities of financial liabilities as at December 31, 2009:

($000s)	**<1 Year**	**1-2 Years**	**2-5 Years**	**Thereafter**
Accounts payable and accrued liabilities	55,890			
Distributions payable	13,790			
Provision for future market and reserves based bonus	2,001	1,041		
Long-term debt[(1)]		435,000		

[(1)]Revolving credit facility renewed annually (*see Note 7*)

16. Capital Disclosures

The Trust's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business.

The Trust manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of our underlying assets. The Trust considers its capital structure to include unitholders' equity, debt and working capital. To maintain or adjust the capital structure, the Trust may from time to time, issue trust units, raise debt and/or adjust its capital spending to manage its current and projected debt levels. The Trust monitors capital based on the following non-GAAP measures: current and projected debt to earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") ratios, payout ratios and net debt levels. To facilitate the management of these ratios, the Trust prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. Currently, all ratios are within acceptable parameters. The annual budget is approved by the Board of Directors. The Trust's unitholders' capital is not subject to any external financial covenants.

There were no changes in the Trust's approach to capital management from the previous year.

($000s)	**December 31, 2009**	December 31, 2008
Unitholders' equity	**612,483**	550,717
Long-term debt	**435,000**	500,000
Working capital (surplus) deficit [1]	**(1,822)**	(32,075)
	1,045,661	1,018,642

[1] Current liabilities less current assets (includes unrealized hedging asset of $8.7 million (2008 - $27.8 million))

17. Supplemental Cash Flow Information

Changes in non-cash working capital balances

($000)	**2009**	2008
Accounts receivable	**7,357**	(17,934)
Prepaid expenses and deposits	**(420)**	1,653
Accounts payable and accrued liabilities	**7,035**	(37,069)
Cash distributions payable	**(2,098)**	1,088
Provision for future performance compensation	**3,042**	(269)
	14,916	(52,531)
Attributable to financing activities	**(2,098)**	1,088
Attributable to investing activities	**12,903**	(14,564)
Attributable to operating activities	**4,111**	(39,055)
	14,916	(52,531)

	2009	2008
Cash interest paid during the year	**16,527**	21,857

18. Contingencies and Commitments

Following is a summary of the Trust's commitments related to operating leases as at December 31, 2009. The Trust has no other contractual obligations or commitments as at December 31, 2009.

($000)	December 31, 2009
2010	1,036
2011	1,036
2012	1,036
2013	1,036
2014	1,036
	5,180

Contingent Liability

From time to time, Peyto is the subject of litigation arising out of its day-to-day operations. Damages claimed pursuant to such litigation, including the litigation discussed below, may be material or may be indeterminate and the outcome of such litigation may materially impact Peyto's financial position or results of operations in the period of settlement. While Peyto assesses the merits of each lawsuit and defends itself accordingly, Peyto may be required to incur significant expenses or devote significant resources to defending itself against such litigation. These claims are not currently expected to have a material impact on Peyto's financial position or results of operations.

Peyto has been named in a Statement of Claim issued by Canadian Natural Resources Limited and affiliates ("CNRL"), claiming $13 million in damages for alleged breaches of duty as operator of jointly owned properties, and an interim and permanent injunction to prevent Peyto from proceeding with the completion of a well on those properties. CNRL alleges that Peyto failed to take proper steps as operator of a joint well (the "Well") on lands that offset 100% Peyto owned lands. Peyto has filed a Statement of Defense defending the allegations set forth in the Statement of Claim. The injunction claimed by CNRL was to prevent Peyto from completing the Well at a target location which had been agreed upon by both parties. Although claimed in the Statement of Claim, CNRL did not apply for an interim injunction, and Peyto completed the Well as planned, but no commercial production was obtained. Affidavits of Records were filed in July, 2006 but CNRL had taken no steps to move the matter forward until February 14, 2007 when it proposed to amend its Statement of Claim to add a subsidiary as an additional Plaintiff and to particularize further its allegations. Accordingly, it remains to be seen whether CNRL will proceed with the action. If the action goes ahead, Peyto intends to defend itself vigorously. Although the outcome of this matter is not determinable at this time, Peyto believes that this claim will not have a material adverse effect on the Trust's financial position or results of operations.

19. Related Party Transactions

An officer of the Trust is a partner of a law firm that provides legal services to the Trust. The fees charged are based on standard rates and time spent on matters pertaining to the Trust and its subsidiaries. For the year ended December 31, 2009, legal fees totaled $0.6 million (2008 - $0.4 million). As at December 31, 2009, an amount due to this firm of $0.5 million was included in accounts payable (2008 - $0.1 million)

Peyto Exploration & Development Corp. Information

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Scott Robinson
Executive Vice-President and Chief Operating Officer

Kathy Turgeon
Vice President, Finance and Chief Financial Officer

Glenn Booth
Vice President, Land

Stephen Chetner
Corporate Secretary

Directors
Don Gray, Chairman
Rick Braund
Stephen Chetner
Brian Davis
Michael MacBean, Lead Independent Director
Darren Gee
Gregory Fletcher

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Deloitte & Touche LLP

Solicitors
Burnet, Duckworth & Palmer LLP

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Union Bank, Canada Branch
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