NEWS RELEASE

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PEYTO ENERGY TRUST ANNOUNCES TEN SUCCESSFUL YEARS WITH FISCAL 2008 YEAR END RESULTS

CALGARY, ALBERTA – Peyto Energy Trust ("Peyto" or the "Trust") is pleased to present the operating and financial results for the fourth quarter and 2008 fiscal year which culminate ten successful years of operation in Western Canada. Peyto has been a leader in the exploration and development of natural gas in Alberta's premier gas exploration area, the Deep Basin.

The following summarizes Peyto's accomplishments over the last ten years:

- Developed 150 net sections of an accumulated land base of 324 net sections (9 townships)
- Internally generated and executed on over 650 gas drilling locations
- Designed and constructed 195 mmcf/d of processing capacity in five 100% owned gas plants
- Installed over 700 wellsites and 750 km of gas gathering system
- Invested over $1.5 billion in capital projects
- Developed over 900 BCFe of proved natural gas reserves, with over 290 BCFe recovered to date
- Generated over $1.45 billion in funds from operations
- Produced over $475 million in crown royalties for Albertans
- Paid out over $800 million in distributions to unitholders ($7.96/unit)
- Accumulated over $900 million in earnings
- Averaged 22% Return on Capital Employed and 44% Return on Equity
- Delivered a ten year compound annual total return of 65%

The Trust's assets exhibited the following attributes for 2008:

- Long reserve life – Proved Producing 14 yrs, Total Proved 17 yrs, Proved plus Probable 23 yrs
- High revenue natural gas - $9.75/mcfe ($58.49/boe) before hedging, $9.54/mcfe ($57.24/boe) after hedging
- Low operating costs (including transportation) - $0.54/mcfe ($3.23/boe)
- Low base general and administrative costs - $0.15/mcfe ($0.91/boe)
- High operating netback - $7.18/mcfe ($43.10/boe), or 74% operating margin before hedging
- High operatorship - over 95% of production
- Debt to funds from operations ratio – 1.8 times (net debt, before provision for future performance based compensation, divided by annualized fourth quarter 2008 funds from operations)

The following summarizes certain performance highlights for the 2008 year:

- Annual Return on Capital Employed (ROCE) was 19%, Return on Equity (ROE) was 33%
- Value creation – invested $139 million in capital and created $299 million of Proved Producing and $300 million of Proved plus Probable undiscounted reserve value, translating into Net Present Value ("NPV") recycle ratios (as defined herein) of 2.1 times
- Net Asset value – the debt adjusted, NPV per unit of the Trust's Total Proved and Proved plus Probable oil and gas assets, discounted at 5%, was $26.19/unit and $33.84/unit, respectively
- Distributions per unit – increased by 5% from $1.68 in 2007 to $1.76 in 2008. Subsequent to year end, distributions were reduced by 20% to an annualized rate of $1.44
- Annual production – decreased 3% from 20,669 boe/d in 2007 to 19,996 boe/d in 2008
- Cost of new reserves (Finding, Development and Acquisition costs "FD&A" inclusive of changes in Future Development Capital "FDC") – increased 36% to $2.88/mcfe ($17.30/boe) for Proved Producing reserves, which when divided into a cash netback of $6.53/mcfe ($39.20/boe) yields a 2.3 times Recycle Ratio
- FD&A cost for Total Proved and Proved plus Probable reserves were $3.17/mcfe and $3.88/mcfe yielding Recycle Ratios of 2.1 and 1.7 times respectively
- Reserve Replacement – Proved Producing 110%, Total Proved 138%, Proved plus Probable 122%

Natural gas volumes are recorded in thousands of cubic feet (mcf), millions of cubic feet (mmcf) and billions of cubic feet (bcf). Natural gas volumes 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 Dec. 31		%	12 Months Ended Dec. 31		%
	2008	2007	Change	**2008**	2007	Change
Operations						
Production						
Natural gas (mcf/d)	**101,907**	104,749	*(3)%*	**100,384**	102,418	*(2)%*
Oil & NGLs (bbl/d)	**3,207**	3,675	*(13)%*	**3,265**	3,599	*(9)%*
Barrels of oil equivalent (boe/d @ 6:1)	**20,191**	21,134	*(4)%*	**19,996**	20,669	*(3)%*
Thousand cubic feet equivalent (mcfe/d @ 6:1)	**121,146**	126,801	*(4)%*	**119,975**	124,011	*(3)%*
Product prices (Inclusive of hedging)						
Natural gas ($/mcf)	**7.99**	7.67	*4%*	**8.64**	8.42	*3%*
Oil & NGLs ($/bbl)	**46.16**	75.23	*(39)%*	**84.78**	67.88	*25%*
Operating expenses ($/mcfe)	**0.43**	0.38	*13%*	**0.44**	0.43	*2%*
Transportation ($/mcfe)	**0.10**	0.09	*11%*	**0.10**	0.09	*11%*
Field netback ($/mcfe)	**6.61**	6.59	-	**7.18**	6.84	*5%*
General & administrative expenses ($/mcfe)	**0.11**	0.15	*(27)%*	**0.15**	0.16	*(6)%*
Interest expense ($/mcfe)	**0.45**	0.53	*(15)%*	**0.50**	0.51	*(2)%*
Financial ($000, except per unit)						
Revenue	**89,377**	99,387	*(10)%*	**418,885**	404,033	*4%*
Royalties	**9,765**	17,080	*(43)%*	**79,821**	70,621	*13%*
Funds from operations	**67,354**	68,976	*(2)%*	**286,907**	279,624	*3%*
Funds from operations per unit	**0.64**	0.65	*(2)%*	**2.71**	2.65	*2%*
Total distributions	**47,664**	44,399	*7%*	**186,731**	177,548	*5%*
Total distributions per unit	**0.45**	0.42	*7%*	**1.76**	1.68	*5%*
Payout ratio (%)	**71**	64	*11%*	**65**	63	*3%*
Earnings	**50,711**	73,289	*(31)%*	**179,397**	208,884	*(14)%*
Earnings per diluted unit	**0.48**	0.69	*(30)%*	**1.69**	1.98	*(15)%*
Capital expenditures	**22,467**	35,546	*(37)%*	**139,324**	121,571	*15%*
Weighted average trust units outstanding	**105,920,194**	105,712,364	-	**105,876,470**	105,670,476	-
As at December 31						
Net debt (before future compensation expense)				**492,644**	457,427	*8%*
Unitholders' equity				**550,717**	528,992	*4%*
Total assets				**1,280,246**	1,192,232	*7%*

Net Earnings	**50,711**	73,289	**179,397**	208,884
Items not requiring cash:				
Provision for (recovery of) performance based compensation	**(5,036)**	(371)	**(269)**	269
Future income tax expense	**1,778**	(30,226)	**32,111**	(12,453)
Depletion, depreciation and accretion	**19,901**	19,151	**75,668**	75,791
Non-recurring items:				
Performance based compensation	-	7,133	-	7,133
Funds from operations [(1)]	**67,354**	68,976	**286,907**	279,624

[(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. Peyto 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.

Historical Perspectives

Peyto Exploration and Development Corporation was founded in 1998 by Don Gray and Rick "Buck" Braund as a junior Exploration and Production (E&P) company. The strategic intent of the company was to focus on low risk, high return, internally generated drilling projects that created long term value by targeting areas with multiple productive horizons that had predictable reserve recoveries. What ensued was a concentrated effort over the next ten years to build high quality, long reserve life natural gas assets in Alberta's Central Deep Basin. In total, $1.54 billion was invested, drilling over 650 gas wells and installing the necessary infrastructure for their production. That capital investment was funded by a combination of funds from operations ($640 million), debt ($493 million), and equity ($410 million). From that investment, a remarkable asset has been built that has delivered over $1.45 billion in funds from operations and is forecast to deliver an additional $2.86 billion (BT NPV_5, debt adjusted of the developed reserves).

In 2003, Peyto Exploration and Development Corp. became Peyto Energy Trust. This structural change was primarily driven by the desire to efficiently share the profits of the business with unitholders. Over the past five years Peyto has been able to return $809 million of accumulated earnings to unitholders in the form of distributions. This level of profitability confirms that the Peyto strategy works. Over the last ten years, Peyto has delivered an average Return on Capital Employed of 22%, Return on Equity of 44% and a compound annual total return of 65%.

2008 in Review

The year 2008 can be best described as a year of volatility. Both sides of Peyto's profitability equation were affected, from commodity prices to service costs. Alberta (AECO) monthly natural gas prices started the year at $6.10/GJ, rose to $10.80/GJ by July, fell to $5.91/GJ by October and ended the year at $6.83/GJ.

Service costs were no different, with input cost of steel and diesel driving the price of tubular goods and certain oilfield services to new highs. Oil Country Tubular Goods (OCTG) began the year at C$1,420/ton, rose to C$3,870/ton in October and softened to C$3,575/ton by year end. This drove the cost of production tubing, for example, from $15/m at the start of the year to $32/m by the end of the third quarter. Unsurprisingly then, Peyto's cost for a typical Deep Basin Cardium gas well rose from $1.8 million to $2.1 million over the year while a Cadomin well cost rose from $3.0 million to $3.5 million.

The profitability of Peyto's capital program in 2008 fell short of the high standard set in previous years. By industry standards, the profitability was very good; however, at Peyto, more is expected. Unitholders should know that the Peyto team is not satisfied with these results and will endeavor to regain the profitability levels that made Peyto one of the most successful North American energy companies of the past ten years.

Capital Expenditures

Net capital expenditures for 2008 totaled $139 million, an increase of 15% from 2007. Capital reinvested was 49% of cash flow, as Peyto continued to balance available funds from operations and bank lines, with distributions and capital investment. The majority of capital was spent on well-related activity with $69.4 million on drilling, $44.9 million on completions, and $18.6 million on wellsite equipment and pipelines. The remaining $6.4 million was invested into new land, seismic and facilities. Drilling activity was concentrated in the Chime area and expanding the boundaries of the Greater Sundance area in both Nosehill and Obed. The following table summarizes capital expenditures for the year.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2008**	2007	**2008**	2007
Land	**730**	-	**2,106**	984
Seismic	**1,036**	464	**3,300**	1,799
Drilling – Exploratory & Development	**15,786**	29,734	**114,302**	96,908
Production Equipment, Facilities & Pipelines	**4,915**	5,326	**19,583**	21,834
Office Equipment	**-**	22	**33**	46
Total Capital Expenditures	**22,467**	35,546	**139,324**	121,571

During the year, 53 gross (41 net) gas wells were drilled, 105 gross (81 net) zones were completed and 101 gross (76 net) zones were brought on production. The total capital per net well of $3.4 million in 2008 represents a 10% increase from $3.1 million per net well in 2007, primarily due to an increase in the average number of completed zones per well from 1.6 to 2.0. The average depth of Peyto's new wells increased another 172m to 2,813m, as drilling prospects continued to evolve to include deeper Cretaceous zones.

Reserves

During 2008, the Trust was again successful in developing high quality, long life reserves "with the drill bit." The following table illustrates the change in reserve volumes and net present value of future cash flow, discounted at 5%, before income tax using forecast pricing.

	As at December 31			
	2008	2007	% Change	% Change Per Unit (NPV_5 debt adjusted)
Reserves				
BCFe				
Proved Producing	**599.8**	595.4	*1%*	*1%*
Total Proved	**762.9**	746.0	*2%*	*2%*
Proved + Probable Additional	**998.3**	988.6	*1%*	*1%*
Net Present Value ($million)				
Discounted at 5%				
Proved Producing	**$2,736**	$2,515	*9%*	*9%*
Total Proved	**$3,267**	$2,966	*10%*	*10%*
Proved + Probable Additional	**$4,077**	$3,703	*10%*	*10%*

Note: Based on the Paddock Lindstrom & Associates report effective December 31, 2008. 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 13, 2009 announcing the 2008 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 2009.

Value Creation

In order to measure investment success, it is necessary to quantify the amount of 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 an ongoing 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 and New Royalty Framework to eliminate 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 2008 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 2008, the net debt had increased by $35 million over the preceeding year while the number of units outstanding had remained essentially the same at approximately 106 million. The change in debt includes all of the capital expenditures 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 $299 million of Proved Producing, $355 million of Total Proven, and $300 million of Proved plus Probable Additional undiscounted reserve value, with $139 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 2008, the Proved Producing NPV recycle ratio is 2.1, compared with 4.7 for 2007 and 2.9 for 2006.

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, 2008.

Value Reconciliation

($millions) Discounted at	Proved Producing 0%	Proved Producing 5%	Proved Producing 10%	Total Proved 0%	Total Proved 5%	Total Proved 10%	Proved + Probable Additional 0%	Proved + Probable Additional 5%	Proved + Probable Additional 10%
Before Tax Net Present Value at Beginning of Year ($millions) Dec. 31, 2007 Evaluation using PLA Jan. 1, 2008 price forecast, less debt	**$4,236**	**$2,057**	**$1,261**	**$5,224**	**$2,508**	**$1,514**	**$7,114**	**$3,245**	**$1,904**
Per Unit Outstanding at Dec. 31, 2007 ($/unit)	$40.07	$19.46	$11.93	$49.42	$23.73	$14.32	$67.30	$30.70	$18.01
Net Change due to AB NRF	**($174)**	**($63)**	**($37)**	**($199)**	**($69)**	**($40)**	**($300)**	**($96)**	**($50)**
2008 sales (revenue less royalties and operating costs)	**($315)**	**($315)**	**($315)**	**($315)**	**($315)**	**($315)**	**($315)**	**($315)**	**($315)**
Net Change due to price forecasts (using PLA Jan 1, 2009 price forecast)	**$735**	**$316**	**$182**	**$930**	**$402**	**$230**	**$1,270**	**$523**	**$291**
Value Change due to discoveries (additions, extensions, transfers, revisions)	**$299**	**$249**	**$241**	**$355**	**$249**	**$223**	**$300**	**$227**	**$207**
Before Tax Net Present Value at End of Year ($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**	**$2,037**
Per Unit Outstanding at Dec. 31, 2008 ($/unit)	$45.13	$21.18	$12.58	$56.60	$26.19	$15.22	$76.18	$33.84	$19.23
Year over Year Change in Before Tax NPV/unit	**13%**	**9%**	**5%**	**15%**	**10%**	**6%**	**13%**	**10%**	**7%**
Year over Year Change in Before Tax NPV/unit including Distribution ($1.76/unit)	**17%**	**18%**	**20%**	**18%**	**18%**	**19%**	**16%**	**16%**	**17%**

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 2008, the Proved plus Probable NPV recycle ratio was 2.2 times. This means for each dollar invested, the Peyto team was able to create 2.2 new dollars of Proved plus Probable reserve value.

2008 Value Creation	**Dec 31, 2008**	Dec 31, 2007	Dec 31, 2006	Dec 31, 2005
NPV Recycle Ratio				
Proved Producing	2.1	4.7	2.9	2.5
Total Proved	2.5	5.5	2.9	2.8
Proved + Probable	2.2	3.8	3.8	3.2

- NPV (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 ($299.3/$139.4)=2.1).

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**
Reserve life index (years)			
Q4 2008 average production – 121.1 mmcfe/d	14	17	23
Finding, development and acquisition costs ($/mcfe)			
2008 (Incl. change in future development capital, "FDC")	$2.88	$3.17	$3.88
2007 (Incl. change in FDC)	$2.11	$1.57	$1.56
3 year average (2006-2008 incl. change in FDC)	$2.65	$2.67	$2.78
2008 change in future development capital ($ millions)		$53.7	$68.8
Reserve replacement ratio	1.1	1.4	1.2
Recycle ratio (Incl. change in FDC)	2.3	2.1	1.7
Distribution life (years)	25	31	42

- *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 ($139.3+$53.7)/(762.9-746.0+43.9)=$3.17/mcfe).*
- *The reserve life index is calculated by dividing the reserves (in mmcfe) in each category by the annualized average production rate in mmcfe/year (eg. Proved Producing 599,760/(121.1x365)=13.6). Peyto believes that the most accurate way to evaluate the current reserve life is by dividing the proved developed producing reserves by the actual fourth quarter average production. For comparative purposes, Peyto believes the proved developed producing reserve life provides the best measure of sustainability.*
- *The distribution life index is calculated by dividing the debt adjusted undiscounted NPV (in millions$) by the Q4 annualized distribution (in million$/year) (eg. Proved Producing ($5,273-$492.6)/($47.7x4) = 25 years).*
- *Recycle ratio is calculated by dividing the field net back per mcfe, before hedging, by the FD&A costs for the period (eg. Proved Producing ($6.53/mcfe+$0.21/mcfe)/$2.88/mcfe = 2.3). In Peyto's opinion, it can be a very good measure of investment performance as long as the replacement reserves are of equivalent quality as the produced reserves. Because the recycle ratio is comparing the netback from existing reserves to the cost of finding new reserves it may not accurately indicate investment success.*
- *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 ((762.9-746.0+44.3)/44.3)=1.4).*

The natural maturation and resulting production rate decline of Peyto's tight gas wells caused the reserve life to increase year over year in all of the reserve categories. The Proved plus Probable reserve life grew from 21 years at the end of 2007 to 23 years at the end of 2008.

Proved Producing Finding, Development and Acquisition ("FD&A") costs increased by 36% in 2008 to $2.88/mcfe ($17.30/boe) due to a 10% increase in the cost per new well combined with a 12% drop in the reserves per new well. In an effort to collect more accurate production data from many of Peyto's lower productivity wells, electronic flow measurement was installed. This resulted in a 3% technical revision to the Proved Producing reserves. This technical revision will not be a recurring item in the future. Future Development Capital ("FDC") for the Total Proved and Probable Additional categories increased by $53.7 million and $68.8 million respectively as a reflection of actual costs incurred in 2008. Peyto believes that the activity slowdown resulting from lower commodity prices will ultimately drive lower service costs which will result in the actual capital costs being less than what is forecast.

Working with less than half of the funds from operations, Peyto replaced 110%, 138% and 122% of production with Proved Producing, Total Proved and Proved plus Probable reserves respectively.

The cost to replace the Proved Producing reserves of $2.88/mcfe was 43% of the achieved 2008 cash netback before hedging effects of $6.74/mcfe. This results in a recycle ratio of 2.3 times. The recycle ratio for Total Proved and Proved plus Probable categories was 2.1 and 1.7 times respectively.

The Distribution Life for Proved Producing, Total Proved and Proved plus Probable reserves increased to 25 years, 31 years and 42 years respectively, primarily due to an increase in the commodity price forecast driven by currency exchange rates.

Quarterly Review

Production for the fourth quarter of 2008 averaged 121.1 mmcfe/d, comprised of 101.9 mmcf/d of natural gas and 3,207 bbl/d of oil and natural gas liquids. A natural gas price of $7.99/mcf was realized in the quarter, after a hedging gain of $0.69/mcf, while an oil and natural gas liquids price of $49.16/bbl was also realized. The 4% reduction in average production rate, combined with a 6% decrease in realized commodity prices, contributed to the 2% overall reduction in funds from operations from $69.0 million in Q4 2007 to $67.4 million in Q4 2008. Fourth quarter 2008 royalties were reduced by the recovery of Deep Gas Royalty Holiday claims.

Operating costs averaged $0.43/mcfe or $2.60/boe in the fourth quarter of 2008 compared to $0.38/mcfe in the fourth quarter of 2007. Increases in fuel, lubricants and power costs resulting from higher oil and electricity prices contributed to this increase. Crown royalties represented $0.88/mcfe, while G&A and interest expenses were $0.11/mcfe and $0.45/mcfe respectively. An increase in pipeline tariffs translated into a $0.01/mcfe increase in transportation expenses. Despite these cost pressures, Peyto's industry leading operating efficiencies combined to yield a quarterly cash netback of $5.47/mcfe before hedging ($6.05/mcfe after hedging) which resulted in a 74% cash flow margin.

Capital expenditures for Q4 2008 totaled $22.5 million, down from $62.3 million in the previous quarter and $35.5 million the year before. For the quarter, drilling and completions accounted for $15.8 million while wellsite equipment, tie-ins and facilities accounted for $4.9 million. Land and seismic purchases adding to new expansion areas accounted for $1.8 million.

Activity Update

To date in 2009, Peyto has drilled 6 gross gas wells (5.5 net) and completed 6 gross zones (5.5 net). Drilling activity has been concentrated in the Sundance and Ansell areas with the only exception being an exploratory test well in a new expansion area. All of the Sundance/Ansell wells will be onstream by the end of April 2009.

Commodity prices, and in particular, AECO monthly natural gas prices have continued their decline from the fourth quarter 2008, falling to their lowest level since October 2006. Peyto has taken the opportunity, during this period of low natural gas prices, to curtail production and conduct necessary compressor maintenance. This has resulted in a reduction of 1,400 mcfe/d or 230 boe/d for the month of February, 2009. To date this year, production has averaged 115 mmcfe/d or 19,200 boe/d.

Marketing

By design, Peyto's marketing strategy smoothes out short term fluctuations in the price of natural gas through future sales. This is done by selling approximately 50% of the total natural gas production (inclusive of Crown Royalty volumes) on the daily and monthly spot markets while the other 50% is hedged. These hedges, or future sales, are meant to be methodical and consistent and to avoid speculation. In general, this approach will show hedging losses when short term prices climb and hedging gains when short term prices fall. Over the long run Peyto expects to break even on forward sales. Cumulative gains since the inception of this hedging strategy in 2003 are $54.3 million to the end of 2008. This hedging approach creates a forward average price typically made up of fifteen to twenty transactions placed over a 12 month period. Peyto generally sells its contracts in either the 7 month summer or the 5 month winter season. In order to minimize counterparty risk, these marketing contracts are with financial institutions that are members of Peyto's loan syndicate.

As at December 31, 2008, the Trust had committed to the future sale of 16,215,000 gigajoules (GJ) of natural gas at an average price of $8.36 per GJ or $9.78 per mcf based on the historical heating value of

Peyto's natural gas. Had these contracts been closed on December 31, 2008, the Trust would have realized a gain in the amount of $30.2 million. Had these same contracts been closed on February 27, 2009, the Trust would have realized a gain in the amount of $50.5 million.

Natural gas prices have been as volatile as ever in 2008 and there is currently much speculation on future prices. This short term volatility does not distract Peyto from its long term focus. Over the last six years, the monthly AECO price has averaged $6.90/GJ. At times, the price has been as high as $12/GJ while at other time it has been as low as $4/GJ. Prices have shown similar volatility over this longer period as they did in 2008 and will likely continue to be volatile in the future. In Peyto's opinion, the price is currently in a low price cycle. It is reasonable to expect that supply and demand will reach equilibrium once again, moving prices back towards historical averages. During this low price cycle, Peyto is in a strong position with its low operating costs, long reserve life and forward sales.

Alberta Royalty Announcement

The Alberta government announced yesterday a "Three Point Incentive Program" to "stimulate new and continued economic activity." The key aspects of the program are a drilling depth-based credit earned for wells drilled in the next year and applicable against existing corporate royalties, as well as a flat 5% royalty rate for a one year period for each new well drilled. Peyto will evaluate the impact of this program but, at first glance, anticipates these combined credits will effectively reduce well costs for the next year by 20%.

2009 Outlook

The importance of having low operating costs, high quality production and long life reserves becomes very apparent in these uncertain times. Unitholders should take comfort knowing that Peyto leads the industry in all of these metrics. On top of the strength of its assets, Peyto also has a ten year track record as a disciplined, profitable energy company. With a staff of only 30 full time employees, Peyto is already lean by any standard. Peyto's debt relative to the value of its assets continues to be on the low end of the industry spectrum. Finally, Peyto's profitability combined with a conservative ratio of developed to undeveloped reserves leaves Peyto far less susceptible to write-downs next year should these current low commodity prices remain.

The challenges facing Peyto this year are no different than those of the first year of operation. Tougher economic times allow Peyto to rise to the top of the industry. At this time, Peyto expects the 2009 capital program to be between $50 and $90 million. This relatively modest capital program will be funded with a combination of funds from operations, working capital and available bank lines which will ensure that financial flexibility is protected.

Conference Call and Webcast

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2008 fourth quarter and full year financial results on Thursday, March 5th, 2009, at 9:00 a.m. Mountain Standard Time (MST), or 11:00 a.m. Eastern Standard Time (EST). To participate, please call 1-416-644-3416 (Toronto area) or 1-800-732-9307 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 21293253 followed by the pound key (#). The replay will be available at 11:00 a.m. MST, 1:00 p.m. EST Thursday, March 5th, 2009 until midnight EST on Thursday, March 12th, 2009. The conference call can also be accessed through the internet at http://www.newswire.ca/en/webcast/viewEvent.cgi?eventID=2511740. 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/Q42008MDandA.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 2:30 p.m. on Wednesday, May 6, 2009 at the Telus Convention Centre, Mcleod Hall B/C, 120 – 9th Avenue SE, Calgary, Alberta.

Darren Gee
President and Chief Executive Officer
March 4, 2009

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 benefitst 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.

National Instrument 51-101 Cautionary Statements

The Canadian Securities Administrators have implemented standards of disclosure for reporting issuers engaged in upstream oil and gas activities effective December 31, 2003. The disclosure standards referred to as National Instrument ("NI") 51-101 establish a regime of continuous disclosure for oil and gas companies and include specific reporting requirements.

- *Peyto's year-end reserve report summarized herein is compliant with NI 51-101. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and hence for years prior to 2003, are compared to "established" reserves which were comprised of proved plus 50 percent of probable reserves.*
- *The term "boes" may be misleading particularly if used in isolation, a boe conversion ratio of 6 mcf : 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead*
- *It should not be assumed that the discounted net present values represent the fair market value of the reserves.*
- *Due to the effects of aggregation, the estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties.*
- *The aggregate of the exploration and development costs incurred in the most recent financial year, and the change during that year in estimated future development costs, generally will not reflect total finding and development costs related to reserve additions for that year.*

Peyto Energy Trust

Consolidated Balance Sheets

($000)

	December 31, 2008	December 31, 2007
Assets		
Current		
Cash	**-**	20,547
Accounts receivable *(Note 5)*	**65,662**	47,728
Financial derivative instruments *(Note 15)*	**27,788**	7,405
Prepaid expenses and deposits	**3,367**	5,020
	96,817	80,700
Financial derivative instruments *(Note 15)*	**2,458**	-
Prepaid capital	**3,069**	-
Property, plant and equipment *(Note 6)*	**1,177,902**	1,111,532
	1,183,429	1,111,532
	1,280,246	1,192,232
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**48,854**	85,923
Cash distributions payable *(Note 10)*	**15,888**	14,800
Provision for future performance based compensation *(Note 13)*	**-**	16
Future income taxes *(Note 14)*	**-**	2,285
	64,742	103,024
Long-term debt *(Note 7)*	**500,000**	430,000
Provision for future performance based compensation *(Note 13)*	**-**	253
Asset retirement obligations *(Note 8)*	**9,479**	6,766
Future income taxes *(Note 14)*	**155,308**	123,197
	664,787	560,216
Unitholders' equity		
Unitholders' capital *(Note 9)*	**410,233**	406,301
Accumulated earnings *(Note 10)*	**110,238**	117,572
Accumulated other comprehensive income	**30,246**	5,119
	550,717	528,992
	1,280,246	1,192,232

See accompanying notes

On behalf of the Board:

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Energy Trust

Consolidated Statements of Earnings

($000 except per unit amounts)

For the years ended December 31,

	2008	2007
Revenue		
Oil and gas sales	**428,047**	358,196
Realized gain (loss) on hedges *(Note 15)*	**(9,161)**	45,837
Royalties	**(79,821)**	(70,621)
Petroleum and natural gas sales, net	**339,065**	333,411
Expenses		
Operating *(Note 11)*	**19,042**	19,359
Transportation	**4,604**	4,296
General and administrative*(Note 12)*	**6,655**	7,125
Performance based compensation *(Note 13)*	**-**	7,133
Future performance based compensation *(Note 13)*	**(269)**	269
Interest on long term debt	**21,857**	23,007
Depletion, depreciation and accretion *(Notes 6 and 8)*	**75,668**	75,791
	127,557	136,980
Earnings before taxes	**211,508**	196,431
Taxes		
Future income tax expense *(Note 14)*	**32,111**	(12,453)
Net earnings for the year	**179,397**	208,884
Earnings per unit *(Note 9)*		
Basic and diluted	**1.69**	1.98

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Comprehensive Income

($000)

For the years ended December 31,

	2008	2007
Net earnings for the year	**179,397**	208,884
Other comprehensive income (loss)		
Change in unrealized gain on hedges (2007 - net of tax of $2,178)	**15,966**	4,880
Realized (gain) loss on hedges (2007 - net of tax $10,356)	**9,161**	(23,202)
Comprehensive Income	**204,524**	190,562

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Accumulated Earnings and Accumulated Other Comprehensive Income (Loss)

($000)

For the years ended December 31,

	2008	2007
Accumulated earnings, beginning of year	**117,572**	86,236
Net earnings for the year	**179,397**	208,884
Distributions *(Note 10)*	**(186,731)**	(177,548)
Accumulated earnings, end of year	**110,238**	117,572

Accumulated other comprehensive income, beginning of year	**5,119**	-
Adoption of financial instruments, net of tax of $10,463 *(Note 2 and 15)*	**-**	23,441
Other comprehensive income (loss)	**25,127**	(18,322)
Accumulated other comprehensive income, end of year	**30,246**	5,119

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Cash Flows

($000)

For the years ended December 31,

	2008	2007
	$	$
Cash provided by (used in)		
Operating Activities		
Net earnings for the year	**179,397**	208,884
Items not requiring cash:		
Future performance based compensation	**(269)**	269
Future income tax expense	**32,111**	(12,453)
Depletion, depreciation and accretion	**75,668**	75,791
Change in non-cash working capital related to operating activities *(Note 17)*	**(38,786)**	16,215
	248,121	288,706
Financing Activities		
Issue of trust units, net of costs	**3,932**	2,825
Cash distributions paid	**(186,731)**	(177,548)
Increase in bank debt	**70,000**	10,000
Change in non-cash working capital related to financing activities *(Note 17)*	**1,088**	5,107
	(111,711)	(159,616)
Investing Activities		
Additions to property, plant and equipment	**(139,324)**	(121,571)
Change in non-cash working capital related to investing activities *(Note 17)*	**(17,633)**	2,222
	(156,957)	(119,349)
Net increase (decrease) in cash	**(20,547)**	9,741
Cash, beginning of year	**20,547**	10,806
Cash, end of year	**-**	20,547

See accompanying notes

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

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.

On January 1, 2008, Peyto completed an internal reorganization. As a result of this reorganization, all of the oil and gas assets of Peyto are now held in Peyto Energy Limited Partnership (the "Partnership"). Peyto Energy Administration Corp. is the administrator of Peyto and Peyto Operating Trust, and Peyto Exploration and Development Corp. is the general partner of the Partnership. Certain subsidiaries of Peyto were amalgamated pursuant to the internal reorganization.

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. 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 net earnings in the period that the change occurs.

Financial Instruments

All financial instruments must initially be recognized at fair value on the balance sheet. The Trust has classified each financial instrument into the following categories: "held for trading" financial assets and financial liabilities; "loans or 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 fair value in either accounts receivable or accrued liabilities. 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

Financial Instruments - Disclosure and Presentation

As of January 1, 2008, the Trust adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Sections, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation" which replaced Section 3861 "Financial Instruments – Disclosure and Presentation". The standards require disclosure on the significance of financial instruments to an entity's financial statements, the risks associated with the financial instruments, and how those risks are managed. Specifically, Section 3862 requires disclosure on the significance of financial instruments to the Trust's financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments. The presentation requirements under Section 3863 are relatively unchanged from Section 3861. Refer to Note 15, "Financial Instruments and Risk Management" for the additional disclosures under Section 3862.

Capital Disclosures

As of January 1, 2008, the Trust adopted CICA Handbook Section 1535 "Capital Disclosures", which requires entities to disclose their objectives, policies and processes for management of capital and, in addition, whether the entity has complied with any externally imposed capital requirements. These disclosures include a description of the Trust's objectives, policies and processes for managing capital, the quantitative data relating to what the entity regards as capital, whether the entity has complied with capital requirements, and, if it has not complied, the consequences of such non-compliance. Refer to Note 16, "Capital Disclosures".

Inventories

As of January 1, 2008, the Trust adopted the CICA section 3031, "Inventories," which replaced CICA section 3030 of the same name. The new guidance provides additional measurement and disclosure requirements and requires the Trust to reverse previous impairment write-downs when there is a change in the situation that caused the impairment. The transitional provisions of section 3031 provided entities with the option of applying this guidance retrospectively and restating prior periods in accordance with section 1506, "Accounting Changes" or adjusting opening retained earnings and not restating prior periods. The adoption of this standard did not have an impact on the Trust's consolidated financial statements.

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.

In April 2008, the CICA published the exposure draft "Adopting IFRSs in Canada". The exposure draft proposes to incorporate IFRSs into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRSs. The Trust is currently reviewing the standards to determine the potential impact on its consolidated financial statements.

Goodwill and Intangible Assets

As of January 1, 2009, the Trust will be required to adopt CICA Handbook Section 3064 "Goodwill and Intangible Assets" which replaces Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs." Various changes have been made to other standards to be consistent with Section 3064, which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. Standards concerning goodwill are unchanged from the standards in Section 3062. The Trust is assessing the impact of this standard on its consolidated financial statements, however, the adoption is not expected to have a material impact on its consolidated financial statements.

5. Accounts Receivable

($000)	**2008**	2007
Accounts receivable – general	**58,394**	47,728
Accounts receivable – income taxes	**7,268**	-
	65,662	47,728

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 $7.3 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 objection has been filed and a notice of appeal will be filed shortly.

6. Property, Plant and Equipment

($000)	**2008**	2007
Property, plant and equipment	**1,551,789**	1,410,767
Accumulated depletion and depreciation	**(373,887)**	(299,235)
	1,177,902	1,111,532

At December 31, 2008 costs of $36.8 (December 31, 2007 - $37.8) related to undeveloped land have been excluded from the depletion and depreciation calculation.

The Trust performed a ceiling test calculation at December 31, 2008 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, 2008 using the following independent engineering consultant's forecasted prices:

	2009	**2010**	**2011**	**2012**	**2013**	**Thereafter (1)**
Edmonton Ref Price ($CDN/bbl)	70.18	77.21	83.93	90.34	98.65	+2%
CDN/US Exchange rate	0.84	0.86	0.88	0.90	0.90	0.90
AECO ($CDN/mmbtu)	7.24	7.90	8.26	8.60	9.13	+2%

(1) Percentage change of 2.0% represents the change in future prices each year after 2013 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, 2009. 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 to prime plus 0.75% 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 2008 was 4.8% (2007 – 5.7%).

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 $9.5 million as at December 31, 2008 (2007 - $6.8 million) based on a total future liability of $34.2 million (2007 - $25.9 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)	**2008**	2007
Balance, December 31, 2007	**6,766**	5,767
Increase in liabilities relating to investing activities	**1,697**	581
Accretion expense	**1,016**	418
Balance, December 31, 2008	**9,479**	6,766

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, 2006	**105,251,394**	**398,434**
Trust units issued by private placement	460,970	7,867
Balance, December 31, 2007	**105,712,364**	**406,301**
Trust units issued by private placement	207,830	3,932
Balance, end of year	**105,920,194**	**410,233**

Per Unit Amounts
Earnings per unit have been calculated based upon the weighted average number of units outstanding during the year of 105,876,470 (2007 - 105,670,476). 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 net 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 new 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 $186.7 million (2007 - $177.5 million total) in accordance with the following schedule:

Production Period	**Record Date**	**Distribution Date**	**Per Unit**
Special Distribution	January 1, 2008	January 15, 2008	$0.0035
January 2008	January 31, 2008	February 15, 2008	$0.14
February 2008	February 29, 2008	March 14, 2008	$0.14
March 2008	March 31, 2008	April 15, 2008	$0.14
April 2008	April 30, 2008	May 15, 2008	$0.14
May 2008	May 31, 2008	June 13, 2008	$0.15
June 2008	June 30, 2008	July 15, 2008	$0.15

July 2008	July 31, 2008	August 15, 2008	$0.15
August 2008	August 31, 2008	September 15, 2008	$0.15
September 2008	September 30, 2008	October 15, 2007	$0.15
October 2008	October 31, 2008	November 14, 2008	$0.15
November 2008	November 30, 2008	December 15, 2008	$0.15
December 2008	December 31, 2008	January 15, 2008	$0.15

Accumulated Earnings and Distributions

($000)	**2008**	2007
Accumulated earnings, beginning of year	**740,038**	531,154
Net earnings for the year	**179,397**	208,884
Total accumulated earnings	**919,435**	740,038
Total accumulated distributions	**(809,197)**	(622,466)
Accumulated earnings, end of year	**110,238**	117,572

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)	**2008**	2007
Field expenses	**30,391**	28,433
Processing and gathering income	**(11,349)**	(9,074)
Total Operating expenses	**19,042**	19,359

12. General and Administrative Expenses

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

($000)	**2008**	2007
General and Administrative expenses	**10,227**	10,242
Overhead recoveries	**(3,572)**	(3,117)
Net General and administrative expenses	**6,655**	7,125

13. Performance Based Compensation

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

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

($millions except unit values)	**2008**	2007	Change
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2009 price forecast	**1,648.0**	1,858.8	
Net debt before performance based compensation	**(492.6)**	(457.4)	
2008 distributions	**-**	(186.7)	
Net value	**1,155.4**	1,214.7	**(59.3)**
Equity adjustment factor*			100%

Equity adjusted increase in value	**(59.3)**
2008 reserve value based compensation @ 4%	-

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

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. For rights vesting in 2008, a tax factor of 1.333 will then be applied to determine the amount to be paid. Commencing for rights vesting in 2009, no tax factor will be applied to determine the amount paid. The 2008 market based component was based on 1.2 million vested rights at an average grant price of $24.94, average cumulative distributions of $5.10 and the five day weighted average closing price of $9.53 (2007 – 1.2 million rights, average grant price of $24.16, average cumulative distributions of $4.73 per unit and five day weighted average closing price of $16.48).

The total amount expensed under these plans was as follows:

($000)	**2008**	2007
Market based compensation	**-**	13
Reserve value based compensation	**-**	7,120
Total	**-**	7,133

For the future market based component, compensation costs as at December 31, 2008 related to 3.1 million non-vested rights with an average grant price of $17.04 were $nil million (2007 - 3.0 million non-vested rights with an average grant price of $21.04 were $0.3 million).

14. Future Income Taxes

($000)	**2008**	2007
Earnings before income taxes	**211,508**	196,431
Statutory income tax rate	**32.50%**	32.12%
Expected income taxes	**68,740**	63,094
Increase (decrease) in income taxes from:		
Corporate income tax rate change	**9,338**	(21,357)
Income attributed to the trust	**(45,516)**	(51,933)
Change in valuation allowance for share issue costs	**(480)**	(1,000)
Other	**29**	(1,257)
Future income tax expense	**32,111**	(12,453)

The net future income tax liability is comprised of:

($000)	**2008**	2007
Financial derivative instruments	**-**	**2,285**
Current future income taxes	**-**	**2,285**
Differences between tax base and reported amounts for depreciable assets	**157,962**	**124,973**
Accrued expenditures	**-**	**(85)**
Provision for asset retirement obligation	**(2,654)**	**(1,691)**
Future income taxes	**155,308**	**123,197**

At December 31, 2008 the Trust has tax pools of approximately $653.8 million (December 31, 2007 - $660.1 million) available for deduction against future income. The Trust has approximately $1.4 million (December 31, 2007 - $2.0 million) in unrecognized future income tax assets and approximately $1.4 million in loss carryforwards (December 31, 2007 - $nil) available to reduce future taxable income.

In 2007, Income Trust tax legislation was passed resulting in a two-tiered tax structure subjecting distributions to the federal corporate income tax rate plus a deemed 13 per cent provincial income tax at the Trust level commencing in 2011. On February 26, 2008 the Federal Government announced as part of the Federal budget that the provincial component of the tax on the Trust is to be calculated based on the general provincial rate in each province in which the Trust has a permanent establishment. This is the same way that a corporation would calculate its provincial tax rate. On February 1, 2009 the Minister of Finance tabled a Notice of Ways and Means which includes the proposed legislation for calculating the provincial tax rate. As the proposed rules were not substantively enacted as of December 31, 2008, the Trust has not reflected a reduced tax rate in the calculation of future income taxes in 2008.

15. Financial Instruments and Risk Management

As described in Note 2, on January 1, 2007, the Trust adopted the new CICA requirements relating to financial instruments. The following summarizes the prospective adoption adjustments that were required as at January 1, 2007.

($000)	December 31, 2006 (As Reported)	Adoption Adjustment	January 1, 2007 (As Restated)
Consolidated Balance Sheets			
Assets			
Financial derivative asset	-	33,904	33,904
Liabilities and Unitholders' Equity			
Future income taxes	135,650	10,463	146,113
Accumulated other comprehensive income	-	23,441	23,441

Market Risk
Market risk is the risk that changes in market prices will affect the Trust’s net 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 its 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 transaction and the underlying basis of the instrument correlates highly with the Trust's exposure. A summary of contracts outstanding in respect of the hedging activities at December 31, 2008 are as follows:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
April 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$7.05/GJ
April 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$6.82/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$7.25/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$7.50/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$7.60/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$8.00/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$8.25/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$8.40/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$8.65/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$9.00/GJ
Nov 1, 2008 to March 31, 2009	Fixed price	5,000 GJ	$9.70/GJ
April 1, 2009 to October 31, 2009	Fixed price	5,000 GJ	$7.85/GJ
April 1, 2009 to October 31, 2009	Fixed price	5,000 GJ	$8.12/GJ

April 1, 2009 to October 31, 2009	Fixed price	5,000 GJ	$8.95/GJ
April 1, 2009 to October 31, 2009	Fixed price	5,000 GJ	$9.30/GJ
April 1, 2009 to October 31, 2009	Fixed price	5,000 GJ	$10.20/GJ
April 1, 2009 to October 31, 2009	Fixed Price	5,000 GJ	$7.50/GJ
April 1 , 2009 to March 31, 2010	Fixed Price	5,000 GJ	$7.65/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	$8.39/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

As at December 31, 2008, the Trust had committed to the future sale of 16,215,000 gigajoules (GJ) of natural gas at an average price of $8.36 per GJ or $9.78 per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on December 31, 2008, the Trust would have realized a gain in the amount of $30.2 million. If the AECO gas price on December 31, 2008 were to increase by $1/GJ, the unrealized gain on these closed contracts would change by approximately $16.2 million. An opposite change in commodity prices rates will result in an opposite impact on net income which would have been reflected in the other comprehensive income of the Trust.

Subsequent to December 31, 2008 the Trust entered into the following contracts:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
April 1 , 2009 to March 31, 2010	Fixed price	5,000 GJ	$6.90/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, 2008 would decrease by $4.5 million. An opposite change in interest rates will result in an opposite impact on net income.

Fair Values of Financial Assets and Liabilities

The Trust's financial instruments include cash, accounts receivable, financial derivative instruments, current liabilities (excluding future income tax), provision for future performance based compensation and long term debt. At December 31, 2008, the carrying value of cash, accounts receivable, financial derivative instruments, 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.

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 significant individual accounts receivable at December 31, 2008, approximately 43% was due from three companies (December 31, 2007 – 31%, one company). Of the Trust's revenue for the year ended December 31, 2008, approximately 90% was received from four companies (December 31, 2007 – 57%, two companies). The maximum exposure to credit risk is represented by the carrying amount on the 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, 2008, 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, 2008:

($000s)	**<1 Year**	**1-2 Years**	**2-5 Years**	**Thereafter**
Accounts payable and accrued liabilities	48,854			
Distributions payable	15,888			
Long-term debt(1)		500,000		

(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, 2008**	December 31, 2007
Unitholders' equity	**550,717**	528,992
Long-term debt	**500,000**	430,000
Working capital (surplus) deficit (1)	**(32,075)**	22,324
	1,018,642	981,316

(1)Current liabilities less current assets (includes unrealized hedging asset of $27.8 million)

17. Supplemental Cash Flow Information

Changes in non-cash working capital balances

($000)	**2008**	2007
Accounts receivable	(17,934)	5,690
Due from private placement	-	5,042
Prepaid expenses and deposits	1,653	(2,339)
Prepaid capital	(3,069)	-
Accounts payable and accrued liabilities	(37,069)	15,087
Cash distributions payable	1,088	64
	(55,331)	23,544
Attributable to financing activities	1,088	5,107
Attributable to investing activities	(17,633)	2,222
Attributable to operating activities	(38,786)	16,215

	2008	2007
Cash interest paid during the year	**21,857**	23,007

18. Contingencies and Commitments

Following is a summary of the Trust's commitments related to operating leases as at December 31, 2008. The trust has no other contractual obligations or commitments as at December 31, 2008.

($000)	$
2009	1,097
2010	1,097
2011	822
	3,016

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, 2008, legal fees totaled \$0.4 million (2007 - \$1.1 million). As at December 31, 2007, an amount due to this firm of \$0.1 million was included in accounts payables (2007 - \$0.8 million)

Peyto Exploration & Development Corp. Information

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President and Chief Executive Officer

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
Ian Mottershead, Chairman
Rick Braund
Don Gray
Brian Davis
Michael MacBean
Darren Gee
Gregory Fletcher

Auditors
Deloitte & Touche LLP

Solicitors
Burnet, Duckworth & Palmer LLP

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