PEYTO

Energy Trust

2008

Annual Report

Chairman's Message

The prevailing sentiment on the world economic stage today is clearly deep fear. The world is experiencing a decline in business activity at a rate unseen in my memory. The reaction has been fiscal and monetary stimulus of enormous proportions, which will probably eventually lead to inflation but this obviously is not the concern at the moment. History teaches us that we will recover from this difficult period. We always do. On this occasion, there may well be significant changes in some financial institutions and the financial behaviour of some societies. The adjustments will probably take time.

In tough economic times, the best protection an enterprise can have is to be the most efficient and profitable in its business. In the current fearful environment, unitholders should take considerable encouragement from the fact that Peyto has industry leading low costs, a lean team of employees, high quality long life reserves, a substantial hedge book at attractive prices, and most importantly a well established habit of being disciplined in the running of the business. Peyto's debt level is manageable, and under constant review by both management and the Board.

Peyto's CEO has provided a thorough assessment of Peyto's activities in this Annual Report, so I will not comment on them further. But given my forty years of activity in capital markets, let me comment on recent stock market behaviour and its impact on Peyto. The U.S. market peaked in August, 2007 and at the time of writing has declined about 53%. The Canadian market peaked in June, 2008 and has now declined 46%. Peyto units also peaked in the summer of 2008, at about $21 ½, and have now declined a remarkable 70%.

The simplicity of Peyto's business model makes valuation of the enterprise quite straightforward. As I have commented in past Annual Reports, the Peyto reserves report intentionally provides masses of data to permit investors to assess the correct net asset value per unit (NAV) using their own assumptions. It is well worth the modest amount of effort to do this. The current unit price implies a combination of sustained low energy prices and a discount rate of something like 15%. This reflects a highly risk averse market, and is consistent with the current pricing of corporate bonds which represent one of the more obvious great values in the market today. (The spread between yields on corporate bonds and those of governments are now the widest I can recall.)

We should remind ourselves that the stock market is a discounting mechanism prone to a kind of bipolar disorder. It is a profound leading indicator. In the depths of a market downswing, the market shortens its focus to the very near term, but once great values have been created and a bit of confidence returns, the market starts to lengthen its focus out to six to eighteen months. The general characteristics of a major stock market cyclical bottom include an extreme level of pessimism, major monetary & fiscal stimulation, and a value investor's paradise. We already have all these.

The precise timing of economic recovery is not knowable because it always depends on psychological factors as much as anything else. This refers mostly to the renewal of confidence of consumers and business executives. Similarly, no one knows when the stock market will commence recovering, but its timing is usually a surprise.

When the stock market does advance, one should expect it to be in the face of a high level of disbelief, worry and skepticism. The economic news will still be awful. In particular, unemployment figures, which are a lagging indicator, will still be deteriorating.

My conclusion regarding the future of Peyto is that once the economy recovers, investors can expect to see rising capital expenditures, and restoration of meaningful growth. The Central Deep Basin where all of Peyto's activities are located is quite an extraordinary area. For the technically skilled, the Basin can produce particularly high returns on capital invested. Peyto is likely to remain a natural gas niche player with many years of highly prospective drilling ahead.

I am confident that Peyto will survive the current difficult environment, and will be well prepared for growth when recovery commences. I note that the desirability of natural gas as a source of energy continues.

C. Ian Mottershead
Chairman of the Board
March 5, 2009

Report from the President

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, an amazing asset has been built - one 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 that has 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

($millions) Discounted at	Proved Producing 0%	5%	10%	Total Proved 0%	5%	10%	Proved + Probable Additional 0%	5%	10%
Before Tax Net Present Value at Beginning of Year ($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 in Peyto's 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.

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.

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 A, 120 – 9th Avenue SE, Calgary, Alberta.

Darren Gee
President and Chief Executive Officer
March 4, 2009

Management’s discussion and analysis

This Management's Discussion and Analysis (“MD&A”) should be read in conjunction with the audited consolidated financial statements of Peyto Energy Trust (the “Trust” or “Peyto”) for the years ended December 31, 2008 and 2007. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”).

The Trust was created by way of a Plan of Arrangement effective July 1, 2003 which reorganized Peyto Exploration & Development Corp. (“PEDC”) from a corporate entity into a trust. Accordingly, the consolidated financial statements were reported on a continuity of interests basis. This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of March 3, 2009. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com.

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 the Peyto Energy Limited Partnership. Peyto Energy Administration Corp. is the administrator of Peyto and Peyto Operating Trust, and PEDC is the general partner of the Partnership. Certain subsidiaries of Peyto were amalgamated pursuant to the internal reorganization.

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

Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before 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 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.

Peyto's foreign ownership level stands at approximately 40% as at January 31, 2009, below the level that would jeopardize Peyto's status as a mutual fund trust under current or proposed legislation.

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

Alberta’s New Royalty Framework

On April 10, 2008, the Alberta Government announced revisions to the New Royalty Framework (“Framework” or “NRF”). The NRF took effect on January 1, 2009. The basis for royalty payments under the new system are as follows:

- Royalty percentages are now dependent upon both well productivity and commodity price
- Gas royalty rates will have a minimum of 5% and a maximum of 50%
- Oil royalty rates will have a minimum of 0% and a maximum of 50%
- In general, under commodity prices of the past few years, well royalty percentages will be higher under this new regime, particularly for higher productivity wells
- Royalty holiday programs have been either eliminated or reduced significantly.

Subsequent to legislation of the NRF, the Alberta Government introduced the Transitional Royalty Plan ("TRP") in response to the anticipated decrease in Alberta development activity resulting from the economic downturn and declining commodity prices. The TRP offers an alternative for new wells drilled on or after November 19, 2008 that meet certain depth criteria. The TRP is in place for a period of five years to December 31, 2013. All wells will convert to the NRF on January 1, 2014. Operators will elect which royalty regime they wish to adopt for each well drilled. The TRP royalties can be beneficial for certain well depths and production rates. Peyto does not anticipate any material benefit from the TRP in 2009. In general, Peyto expects to see more volatility in royalty rates as a result of the NRF.

The Alberta government announced 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 over 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% thereby offsetting the low near term commodity price outlook.

Federal Government's Trust Tax Legislation

On June 12, 2007, Bill C-52 (the "SIFT Rules") enacted the October 31, 2006 proposal to impose a new tax on distributions from flow-through entities, including publicly traded income trusts. Under the SIFT Rules, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. In simplified terms, under the proposed tax plan, income distributions will first be taxed at the trust level at a special rate estimated to be the Federal Corporate rate and applicable provincial corporate rate. Income distributions to unitholders will then be treated as dividends from a Canadian corporation. Individual unitholders will be eligible for the dividend tax credit. Tax-deferred accounts (RRSPs, RRIFs and Pension Plans) will continue to pay no tax on distributions but will not be eligible to use the dividend tax credit. Non-resident unitholders will be taxed on distributions at the non-resident withholding tax rate for dividends. The net impact on individual Canadian taxable investors is expected to be minimal because they can take advantage of the dividend tax credit. However, as a result of the tax at the trust level, distributions to tax-deferred accounts and non-residents will be reduced. On the basis of proposed legislation it is anticipated that the tax will be 26.5%.

On July 14, 2008, the Department of Finance released proposed amendments (the "Conversion Rules") to the Income Tax Act (Canada) to facilitate the conversion of existing income trusts into corporations. In general, the proposed amendments will permit a conversion to be tax deferred for both the unitholders and the income trust. However, the Conversion Rules provide alternative approaches to completing a tax deferred conversion. The Department of Finance requested comments on the Conversion Rules by September 15, 2008 and it is anticipated that there will be further amendments to the Conversion Rules. Management and the Board of Directors continue to review the impact of the Trust tax on our business strategy and while there has not been a decision as to Peyto's future direction, at this time we are of the opinion that the conversion from a trust into a corporation may be the most logical and tax efficient alternative for unitholders. At the present time, Peyto believes that if structural or other similar changes are not made, the relative after-tax distribution amount in 2011 to taxable Canadian investors will remain approximately the same, however, will decline for both tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) and foreign investors.

Climate Change Programs
Peyto looks to both Alberta provincial authorities and to Canada's federal authorities for direction regarding environmental and climate change legislation.

In January 2008 the Alberta Government released Alberta's new Climate Change Strategy. The new strategy focuses on implementing carbon capture and storage, conserving and using energy efficiently, and greening energy production. The provincial vision is significant reductions in emissions for both the mid-term (2014) and long term (2050). To date, the only tangible legislation set forth pertains to large emitting facilities (over 100,000 tonnes per year) and excludes any of Peyto current facilities. The goal of that legislation is to reduce emissions by 20 Mt by 2010, by 50 Mt by 2020, and 200 Mt by 2050. No other new provincial legislation has been developed at this time.

At the federal level, the April 2007 Regulatory Framework for Air Emissions laid out the broad vision for reduction of industrial emissions of both greenhouse gases and air pollutants. This plan calls for greenhouse gas emissions to be reduce by 20 per cent below 2006 levels by 2020. All covered industrial sectors are required to reduce emissions by 18% below 2006 levels by 2010, with a 2% continuous improvement every year after. On March 10, 2008 the federal government announced further details of the April 2007 regulatory framework. The March 10 framework elaborates on fixed process emissions, new facility regulations, cleaner fuel standards, carbon capture and storage, and compliance mechanisms (Canada's domestic offset system, Clean Development Mechanism, Credit for Early Action Program, Technology Fund). The emission intensity targets remain the same as previously laid out in the April 2007 framework.

Currently the framework is being translated into actual regulations. The final regulations are expected to be approved and published in Canada Gazette, Part II in Fall 2009, with greenhouse gas provisions of the regulations coming into force on January 1, 2010.

As mentioned in the October 2006 Notice of Intent to develop and Implement Regulations and Other Measures to Reduce Emissions, the government sill intends to transition from energy-intensity targets to fixed emission caps in the 2020-2025 period.

Peyto will monitor the progress of the pending Federal regulations and expects clarity by the end of this year to determine what actions will be required and what impacts will occur from those regulations.

United States Proposed Changes to Qualifying Dividends
A bill was introduced into United States Congress on March 23, 2007 that could deny qualified dividend income treatment to the distributions made by the Trust to its U.S. unitholders. The bill is in the first step of the legislative process and it is uncertain whether it will eventually be passed into law in its current form. If the bill is passed in its current form, distributions received by U.S. unitholders would no longer qualify for the 15% qualified dividend tax rate.

OVERVIEW

Peyto is a Canadian energy trust involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2008, the total Proved plus Probable reserves were 998.3 billion cubic feet equivalent (166.4 million barrels of oil equivalent) with a reserve life of 23 years as evaluated by the independent petroleum engineers. Production is weighted approximately 85% natural gas and 15% natural gas liquids and oil.

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

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

Operating results over the last ten years indicate that these principles have been successfully implemented. This business model makes Peyto a unique energy trust.

ANNUAL FINANCIAL INFORMATION

The following is a summary of selected financial information of the Trust for the periods indicated. Reference should be made to the audited consolidated financial statements of the Trust, which are available at www.sedar.com.

Year Ended December 31 ($000 except per unit amounts)	**2008**	2007	2006
Total revenue (before royalties)	**418,886**	404,033	439,008
Funds from operations	**286,907**	279,624	305,845
Per unit – basic and diluted	**2.71**	2.65	2.93
Earnings	**179,397**	208,884	195,228
Per unit – basic and diluted	**1.69**	1.98	1.86
Total assets	**1,280,246**	1,192,232	1,136,700
Total long-term debt	**500,000**	430,000	420,000
Cash distributions per unit	**1.76**	1.68	1.66

QUARTERLY FINANCIAL INFORMATION

	2008				2007			
($000 except per unit amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (net of royalties)	**79,612**	86,607	87,682	85,164	82,307	75,589	83,017	92,499
Funds from operations	**67,354**	74,485	74,113	70,955	68,976	62,938	69,345	78,364
Per unit – basic and diluted	**0.64**	0.70	0.70	0.67	0.65	0.60	0.66	0.74
Earnings	**50,711**	64,834	31,412	32,440	73,289	39,886	38,825	56,883
Per unit – basic and diluted	**0.48**	0.61	0.30	0.31	0.69	0.37	0.37	0.54
Distributions	**47,664**	47,664	46,605	44,798	44,399	44,399	44,399	44,350
Per unit – basic and diluted	**0.45**	0.45	0.44	0.42	0.42	0.42	0.42	0.42

RESULTS OF OPERATIONS

Production

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2008	2007	**2008**	2007
Natural gas (mmcf/d)	**101,907**	104,749	**100,384**	102,418
Oil & natural gas liquids (bbl/d)	**3,207**	3,675	**3,265**	3,599
Barrels of oil equivalent (boe/d)	**20,191**	21,134	**19,996**	20,669
Thousand cubic feet equivalent (mcfe/d)	**121,146**	126,801	**119,975**	124,011

Natural gas production averaged 101.9 mmcf/d in the fourth quarter of 2008, 3% lower than the 104.7 mmcf/d reported for the same period in 2007. Oil and natural gas liquids production averaged 3,207 bbl/d, a decrease of 13% from 3,675 bbl/d reported in the prior year. Production for the year decreased 3% from 124,011 mcfe/d to 119,985 mcfe/d (20,669 boe/d to 19,996 boe/d). The production decreases are attributable to natural production declines.

Commodity Prices

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2008	2007	**2008**	2007
Natural gas ($/mcf)	**7.30**	6.57	**8.87**	7.24
Hedging – gas ($/mcf)	**0.69**	1.10	**(0.23)**	1.18
Natural gas – after hedging ($/mcf)	**7.99**	7.67	**8.64**	8.42
Oil and natural gas liquids($/bbl)	**49.16**	76.67	**85.52**	66.68
Hedging – oil ($/bbl)	**-**	(1.44)	**(0.74)**	1.20
Oil and natural gas liquids – after hedging ($/bbl)	**49.16**	75.23	**84.78**	67.88
Total Hedging ($/boe)	**3.49**	5.19	**(1.25)**	6.08
Total Hedging ($/mcfe)	**0.58**	0.86	**(0.21)**	1.01

Peyto's natural gas price before hedging averaged $7.30/mcf during the fourth quarter of 2008, an increase of 11% from $6.57/mcf reported for the equivalent period in 2007. Oil and natural gas liquids prices averaged $49.16/bbl down 36% from $76.67/bbl a year earlier. Average natural gas prices for the year were up 23% at $8.87/mcf while oil and natural gas liquids prices were up 28% at $85.52/bbl compared to 2007. Hedging activity for fiscal 2008 decreased Peyto's price achieved by $0.21/mcf or $1.25/boe. Natural gas prices rose sharply through the first seven months of 2008 and have fallen steadily since peaking in July.

Revenue

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2008**	2007	**2008**	2007
Natural gas	**68,396**	63,374	**325,840**	270,602
Oil and natural gas liquids	**14,501**	25,923	**102,206**	87,594
Hedging gain (loss)	**6,480**	10,090	**(9,161)**	45,837
Total revenue	**89,377**	99,387	**418,885**	404,033

For the three months ended December 31, 2008, gross revenue decreased 10% to $89.4 million from $99.4 million for the same period in 2007. The decrease in revenue for the quarter was a result of decreased production volumes and decreased natural gas liquids prices as detailed in the following table:

	Three Months ended Dec 31			Twelve Months ended Dec. 31		
	2008	2007	**$million**	2008	2007	**$million**
Total Revenue, Dec 31, 2007			**99.4**			**404.0**
Revenue change due to:						
Natural gas						
Volume (mmcf)	9,375	9,637	**(2.0)**	36,740	37,382	**(5.4)**
Price ($/mcf)	7.99	7.67	**3.0**	8.64	8.42	**8.1**
Oil & NGL						
Volume (mbbl)	295	338	**(3.3)**	1,195	1,314	**(8.0)**
Price ($/bbl)	49.16	75.23	**(7.7)**	84.78	67.88	**20.2**
Total Revenue, Dec 31, 2008			**89.4**			**418.9**

Royalties

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

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000 except per unit amounts)	**2008**	2007	**2008**	2007
Royalties,	**9,765**	17,080	**79,821**	70,621
% of sales before hedging	**12**	19	**19**	20
% of sales after hedging	**11**	17	**19**	17
$/boe	**5.26**	8.78	**10.91**	9.36
$/mcfe	**0.88**	1.46	**1.82**	1.56

For the fourth quarter of 2008, royalties averaged $0.88/mcfe ($5.26/boe) or approximately 11% of Peyto's total petroleum and natural gas sales. Royalties for the year were 19% of sales in 2008 compared to 17% in 2007. The royalty rate expressed as a percentage of sales will fluctuate from period to period due to the fact that the Alberta Reference Price can differ significantly from the commodity prices obtained by the Trust and that hedging gains and losses are not subject to royalties. As average per well production rates decline, the associated effective Crown Royalty rate will decrease. Fourth quarter 2008 royalties were reduced by the recovery of Deep Gas Royalty Holiday claims. The Deep Gas Royalty Holiday program ended December 31, 2008. In its 10 year history, Peyto has invested over $1.5 billion in capital projects and has found and developed gas reserves that have paid over $475 million in royalties to Albertans.

Operating Costs & Transportation

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

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2008	2007	**2008**	2007
Operating costs ($000)				
Field expenses	**7,789**	7,136	**30,391**	28,433
Processing and gathering income	**(2,950)**	(2,753)	**(11,349)**	(9,074)
Total operating costs	**4,839**	4,383	**19,042**	19,359
$/boe	**2.60**	2.25	**2.60**	2.57
$/mcfe	**0.43**	0.38	**0.44**	0.43
Transportation	**1,158**	1,052	**4,604**	4,296
$/boe	**0.62**	0.54	**0.63**	0.57
$/mcfe	**0.10**	0.09	**0.10**	0.09

Operating costs were $4.8 million in the fourth quarter of 2008 compared to $4.4 million during the same period a year earlier. Processing and gathering income has increased as third party volumes have increased significantly. Transportation expense increased due to an increase in pipeline tariffs effective January 1, 2008. On a unit-of-production basis, operating costs averaged $0.43/mcfe ($2.60/boe) in the fourth quarter of 2008 compared to $0.38/mcfe ($2.25/boe) for the fourth quarter of 2007. Operating costs for the year averaged $0.44/mcfe ($2.60/boe) in 2008 compared to $0.43/mcfe ($2.57/boe) in 2007.

Netbacks

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

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($/mcfe)	**2008**	2007	**2008**	2007
Gross Sale Price	**7.44**	7.66	**9.75**	7.93
Hedging gain (loss)	**0.58**	0.86	**(0.21)**	1.01
Net Sale Price	**8.02**	8.52	**9.54**	8.92
Less:				
Royalties	**0.88**	1.46	**1.82**	1.56
Operating costs	**0.43**	0.38	**0.44**	0.43
Transportation	**0.10**	0.09	**0.10**	0.09
Field netback	**6.61**	6.59	**7.18**	6.84
General and administrative	**0.11**	0.15	**0.15**	0.16
Interest on long-term debt	**0.45**	0.53	**0.50**	0.51
Cash netback	**6.05**	5.91	**6.53**	6.17
Cash netback ($/boe)	**36.26**	35.49	**39.20**	37.07

General and Administrative Expenses

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000 except per unit amounts)	**2008**	2007	**2008**	2007
G&A expenses	**2,274**	2,648	**10,227**	10,242
Overhead recoveries	**(1,033)**	(950)	**(3,572)**	(3,117)
Net G&A expenses	**1,241**	1,698	**6,655**	7,125
$/boe	**0.67**	0.87	**0.91**	0.94
$/mcfe	**0.11**	0.15	**0.15**	0.16

General and administrative expenses before overhead recoveries remained relatively constant in the fourth quarter of 2008, as compared to the same period in 2007. Net of overhead recoveries associated with the capital expenditures program, general and administrative costs decreased to $0.11/mcfe ($0.67/boe) in the fourth quarter of 2008, from $0.15/mcfe ($0.87/boe) in the fourth quarter of 2007. Fourth quarter 2008 capital overhead recoveries were 8.7% higher than fourth quarter 2007 recoveries and were 14.6% higher on an annual basis. General and administrative expenses for 2008 averaged $0.15/mcfe ($0.91/boe) in 2008 compared to $0.16/mcfe ($0.94/boe) in 2007.

Interest Expense

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2008	2007	**2008**	2007
Interest expense ($000)	**5,020**	6,198	**21,857**	23,007
$/boe	**2.70**	3.19	**2.99**	3.05
$/mcfe	**0.45**	0.53	**0.50**	0.51
Average interest rate	**4.0%**	6.0%	**4.8%**	5.7%

2008 interest expense was $21.9 million or $0.50/mcfe ($2.99/boe) compared to $23.0 million or $0.51/mcfe ($3.05/boe) a year earlier. Although interest rates have continued to be favorable, they have been increasingly volatile due to the global economic crisis. Interest rates are not expected to increase substantially in the short-term, however the stamping fee component of interest expense is expected to rise.

Depletion, Depreciation and Accretion

The 2008 provision for depletion, depreciation and accretion totaled $75.7 million as compared to $75.8 million in 2007. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $ 1.72/mcfe ($10.34/boe) as compared to $1.67/mcfe ($10.05/boe) in 2007. Increases or decreases in the depletion rate on a unit-of-production basis are influenced by the reserves added through Peyto's drilling program.

Income Taxes

The 2008 provision for future income tax expense was $32.1 million (2007 – recovery of $12.5 million). Increases in capital spending and distributions shorten the period over which timing differences between the accounting and tax basis of assets reverse. As a result, higher reversals occur in the years subject to a zero% tax rate rather than in years subject to the SIFT tax rate, reducing the tax rate applied to the timing differences in calculating future income taxes by approximately 7%. This resulted in a reduction of the future income tax liability and corresponding future tax recovery. Peyto's trust structure is unique and was designed to provide for discretion at the operating trust level to distribute taxable income to the Trust. Resource pools are generated from the capital program, which are available to offset current and future income tax liabilities. Unitholders benefit as the Trust may use these resource pools to increase the tax free return of capital component of the cash distributions. As a result of the internal reorganization that took place January 1, 2008, the tax rate applied to differences between the accounting basis and tax basis of the Trust's assets increased by approximately 3% (the difference between future corporate income tax rates and future tax rates applicable to trusts). 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.

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 has 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.

MARKETING

Commodity Price Risk Management

Effective January 1, 2007, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") Section 3855, "Financial Instruments - Recognition and Measurement," Section 3865, "Hedges," Section 1530, "Comprehensive Income" and Section 3861, "Financial Instruments – Disclosure and Presentation." The Trust has adopted these standards retroactively without restatement and the comparative interim consolidated financial statements have not been restated. Transition amounts have been recorded in retained earnings or accumulated other comprehensive income. See Note 2 to the Consolidated Financial Statements.

The Trust is a party to certain derivative financial instruments, including fixed price contracts. The Trust enters into these forward contracts with well established counter-parties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. During 2008, a hedging loss of $9.2 million was recorded as compared to a hedging gain of $45.8 million in 2007. A summary of contracts outstanding in respect of the hedging activities 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
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	$8.35/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.

Commodity Price Sensitivity

Peyto's earnings are largely determined by commodity prices for crude oil and natural gas including the US/Canadian dollar exchange rate. Volatility in these oil and gas prices can cause fluctuations in Peyto's earnings over which the Trust has no control. Low operating costs and long reserve life reduce Peyto's sensitivity to changes in commodity prices.

Currency Risk Management

The Trust is exposed to fluctuations in the Canadian/US dollar exchange ratio since the natural gas and oil sales are effectively priced in US dollars and converted to Canadian dollars. In the short term, this risk is mitigated indirectly as a result of a commodity hedging strategy that is conducted in Canadian currency. Over the long term, the Canadian dollar tends to rise as oil prices rise. There is a similar correlation between oil and gas prices. Currently Peyto has not entered into any agreements to further manage this specific risk.

Interest Rate Risk Management

The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently there are no agreements to manage this risk. At December 31, 2008, the increase or decrease in earnings for each 100 bps (1%) change in interest rate paid on the outstanding revolving demand loan amounts to approximately $4.5 million per annum. Average debt outstanding for 2008 was $454.7 million.

LIQUIDITY AND CAPITAL RESOURCES

Funds from Operations

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000 except per unit amounts)	**2008**	2007	**2008**	2007
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 & accretion	**19,901**	19,151	**75,668**	75,791
Non-recurring items:				
Market and reserve value performance based compensation	-	7,133	-	7,133
Funds from operations	**67,354**	68,976	**286,907**	279,624
Funds from operations per unit	**0.64**	0.65	**2.71**	2.65

For the quarter ended December 31, 2008, funds from operations totaled $67.4 million or $0.64 per unit, as compared to $69.0 million, or $0.65 per unit during the same period in 2007. Peyto's policy is to balance distributions to unitholders and funding for a capital program with cashflow and available bank lines. Earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond Peyto's control. Current volatility in commodity prices creates uncertainty as to the funds from operations and capital expenditure budget. Accordingly, results are assessed throughout the year and operational plans revised as necessary to reflect the most current information.

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

Bank Debt

The Trust has an extendible revolving term credit facility with a syndicate of financial institutions in the amount of $550 million including a $530 million revolving facility and a $20 million operating facility. Available borrowings are limited by a borrowing base, which is based on the value of petroleum and natural gas assets as determined by the lenders. The loan is reviewed annually and may be extended at the option of the lender for an additional 364 day period. If not extended, the revolving facility will automatically convert to a one year and one day non-revolving term loan. The loan has therefore been classified as long-term on the balance sheet. The average borrowing rate for 2008 was 4.8% (2006 – 5.7%). The Trust is in compliance with all terms and conditions of its credit facility.

At December 31, 2008, $500 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At December 31, 2008, the working capital surplus was $32.1 million (including a non-cash current asset of $27.8 million for unrealized mark to market future hedging gains).

Peyto believes that funds generated from operations, together with borrowings under the credit facility and proceeds from equity issued will be sufficient to finance current operations and the planned capital expenditure program. The total amount of capital invested in 2009 will be driven by the number and quality of projects generated. Capital will only be invested if it meets the long term objectives of the Trust. The majority of the capital program will involve drilling, completion and tie-in of low risk development gas wells. Peyto has the flexibility to match planned capital expenditures to actual cash flow.

As a result of the weakened global economic situation, the Trust may have restricted access to capital and increased borrowing costs. Although the Trust's business and asset base have not changed, the lending capacity of all financial institutions has been diminished and risk premiums have increased. These issues may impact the Trust as it reviews financing alternatives for the 2009 capital program and manages future cash flow.

Capital

On March 17, 2008 the Trust completed a private placement of 207,830 trust units to employees and consultants for net proceeds of $3.9 million ($18.92 per unit). These trust units were issued on March 17, 2008. On December 31, 2008, 105,920,194 trust units were outstanding (December 31, 2007 – 105,712,364).

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, December 31, 2008	**105,920,194**	**410,233**

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 reserve 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%. This methodology can generate interim results which vary significantly from the final compensation paid. No provision for compensation expense was recorded for the year ended December 31, 2008.

($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 was 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.

Based on the five day weighted average trading price of the trust units for the year ended December 31, 2008, compensation costs related to 1.2 million vested rights (1% of the total number of trust units outstanding), 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, is $nil. The Trust records a non-cash provision for future compensation expense over the life of the rights. The cumulative provision is $nil.

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

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

Capital Expenditures

Net capital expenditures for the fourth quarter of 2008 totaled $22.5 million. Exploration and development related activity represented $17.6 million or 78% of the total, while expenditures on facilities, gathering systems and equipment totaled $4.9 million or 22% of the total. 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

Cash Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2008	2007	**2008**	2007
Funds from operations ($000)	**67,354**	68,976	**286,907**	279,624
Total distributions ($000)	**47,664**	44,399	**186,731**	177,548
Total distributions per unit ($)	**0.45**	0.42	**1.76**	1.68
Payout ratio (%)	**71**	64	**65**	63

Peyto's policy is to balance distributions to unitholders and funding for a capital program with cashflow and available bank lines. The Board of Directors is prepared to adjust the payout levels to achieve the desired distributions while maintaining an appropriate capital structure. For Canadian income tax purposes distributions made are considered a combination of income and return of capital. The portion that is return of capital reduces the adjusted cost base of the units. As a result of the volatility in commodity prices and in order to maintain financial flexibility in light of the on-going global economic and financial crisis, the Trust announced a decrease in distributions to $0.12 per unit subsequent to year end.

Accumulated Earnings and Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2008**	2007	**2008**	2007
Opening accumulated earnings	**868,724**	666,749	**740,038**	531,154
Net earnings for the period	**50,711**	73,289	**179,397**	208,884
Total accumulated earnings	**919,435**	740,038	**919,435**	740,038
Total accumulated distributions	**(809,197)**	(622,466)	**(809,197)**	(622,466)
Accumulated earnings per Balance Sheet	**110,238**	117,572	**110,238**	117,572

Since inception, Peyto has accumulated earnings of $919.4 million and distributed $809.2 million to unitholders.

Contractual Obligations and Commitments

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

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

From time to time, Peyto is the subject of litigation arising out of its day-to-day operations. 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. Such claims are not currently expected to have a material impact on Peyto's financial position or results of operations.

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.

INCOME TAXES

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

Canadian Taxpayers

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

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

For 2008, the Trust paid distributions to the unitholders in the amount of $186.7 million (2007 - $177.5 million) 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

US Taxpayers

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

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

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

A bill was introduced into United States Congress on March 23, 2007 that could deny qualified dividend income treatment to the distributions made by the Trust to its U.S. unitholders. The bill is in the first step of the legislative process and it is uncertain whether it will eventually be passed into law in its current form. If the bill is passed in its current form, distributions received by U.S. unitholders would no longer qualify for the 15 per cent qualified dividend tax rate.

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

RISK MANAGEMENT

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

Expected funds from operations depends largely on the volume of petroleum and natural gas production and the price received for such production, along with the associated costs. The price received for oil depends on a number of factors, including West Texas Intermediate oil prices, Canadian/US currency exchange rates, quality differentials and Edmonton par oil prices. The price received for natural gas production is primarily dependent on current Alberta market prices. Peyto’s marketing strategy is designed to smooth out short term fluctuations in the price of natural gas through future sales. It is meant to be methodical and consistent and to avoid speculation.

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

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

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

Access to markets may be restricted at times by pipeline or processing capacity. These risks are minimized by controlling as much of the processing and transportation activities as possible and ensuring transportation and processing contracts are in place with reliable cost efficient counter-parties.

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

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

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

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Trust is made known to the Trust's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Trust in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's disclosure controls and procedures at the financial year end of the Trust and have concluded that the Trust's disclosure controls and procedures are effective at the financial year end of the Trust for the foregoing purposes.

Internal Control over Financial Reporting
The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's internal control over financial reporting at the financial year end of the Trust and concluded that the Trust's internal control over financial reporting is effective, at the financial year end of the Trust, for the foregoing purpose.

The Trust is required to disclose herein any change in the Trust's internal control over financial reporting that occurred during the period beginning on October 1, 2008 and ended on December 31, 2008 that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting. No material changes in the Trust's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

It should be noted that a control system, including the Trust's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

CRITICAL ACCOUNTING ESTIMATES

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

The Trust's estimated quantities of proved and probable reserves at December 31, 2008 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 10 consecutive years.

Depletion and Depreciation Estimate
The full cost method of accounting for petroleum and natural gas operations is followed whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of

drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

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

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

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

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

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

Reserve Value Performance Based Compensation
The reserve value based compensation is calculated using the year end independent reserves evaluation which was completed in January 2008. A quarterly provision for the reserve value based compensation is calculated using estimated proved producing reserve additions adjusted for changes in debt, equity and distributions. Actual proved producing reserves additions and forecasted commodity prices could vary significantly from those estimated and may have a material effect on the calculation.

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

Financial Instrument Disclosures
As of January 1, 2008, the Trust adopted CICA Handbook Sections, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation" which replaced Section 3861. These standards require disclosure of the significance of financial instruments to an entity's financial statements, the risks associated with the financial instruments, and how those risks are managed. The presentation standard essentially carries forward the current presentation requirements. . Refer to Note 10 to the Consolidated Financial Statements 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. Refer to Note 11 to the Consolidated Financial Statements.

Accounting Changes
Voluntary changes in accounting policy are made only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in earnings. When the Trust has not applied a new primary source of GAAP that has been issued, but is not effective, the Trust will disclose the fact along with information relevant to assessing the possible impact that application of the new primary source of GAAP will have on the financial statements in the period of initial application.

Adoption of 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. The Trust continues to assess the impact of the convergence of Canadian GAAP and IFRS. At this time, the Trust has appointed internal staff along with sponsorship from the senior leadership team to review the impact of converting to IFRS on the accounting policies, information and computer systems, internal and disclosure controls, financial reporting in addition to the changes in the Trust's financial statements.

Goodwill and Intangible Assets
As of January 1, 2009, the Trust will be required to adopt new 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 the new Section 3064, which establishes standards for the recognition, measurement, presentation and disclosure of goodwill and of intangible assets. Standards concerning goodwill are unchanged from the standards in the previous Section 3062. The Trust is assessing the impact of this new standard on its consolidated financial statements, however, the adoption is not expected to have a material impact on its consolidated financial statements.

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

Quarterly information

	2008				2007
	Q4	Q3	Q2	Q1	Q4
Operations					
Production					
Natural gas (mcf/d)	**101,907**	100,324	97,819	101,468	104,749
Oil & NGLs (bbl/d)	**3,207**	3,199	3,226	3,430	3,675
Barrels of oil equivalent (boe/d @ 6:1)	**20,191**	19,920	19,530	20,342	21,134
Thousand cubic feet equivalent (mcfe/d @ 6:1)	**121,146**	119,520	117,177	122,050	126,801
Average product prices					
Natural gas ($/mcf)	**7.99**	8.81	9.32	8.49	7.67
Oil & natural gas liquids ($/bbl)	**49.16**	99.28	107.45	83.45	75.23
$/MCFE					
Average sale price ($/mcfe)	**8.02**	10.05	10.75	9.40	8.52
Average royalties paid ($/mcfe)	**0.88**	2.18	2.52	1.73	1.46
Average operating expenses ($/mcfe)	**0.43**	0.42	0.43	0.45	0.38
Average transportation costs ($/mcfe)	**0.10**	0.10	0.11	0.10	0.09
Field netback ($/mcfe)	**6.61**	7.35	7.69	7.12	6.59
General & administrative expense ($/mcfe)	**0.11**	0.12	0.18	0.20	0.15
Interest expense ($/mcfe)	**0.45**	0.46	0.56	0.53	0.53
Cash netback ($/mcfe)	**6.05**	6.77	6.95	6.39	5.91
Financial ($000 except per unit)					
Revenue	**89,377**	110,537	114,543	104,428	99,387
Royalties	**9,765**	23,930	26,861	19,264	17,080
Funds from operations	**67,354**	74,485	74,113	70,955	68,976
Funds from operations per unit	**0.64**	0.70	0.70	0.67	0.65
Total distributions	**47,664**	47,664	46,605	44,798	44,399
Total distributions per unit	**0.45**	0.45	0.44	0.42	0.42
Payout ratio	**71%**	64%	63%	63%	64%
Earnings	**50,711**	64,834	31,412	32,440	73,289
Earnings per diluted unit	**0.48**	0.61	0.30	0.31	0.69
Capital expenditures	**22,467**	62,271	21,528	33,058	35,546
Weighted average trust units outstanding	**105,920,194**	105,920,194	105,920,194	105,744,338	105,712,364

Deloitte.

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To the Unitholders of:
Peyto Energy Trust:

Auditors' Report

We have audited the consolidated balance sheets of Peyto Energy Trust (the "Trust") as at December 31, 2008 and 2007 and the consolidated statements of earnings, comprehensive income, accumulated earnings and accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta
February 20, 2009

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

($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

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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