NEWS RELEASE

MARCH 6, 2013 **SYMBOL: PEY – TSX**

PEYTO ANNOUNCES Q4 AND YEAR END 2012 REPORT TO SHAREHOLDERS WITH CORRECTED FUNDS FROM OPERATIONS

CALGARY, ALBERTA – Peyto Exploration & Development Corp. ("Peyto" or the "Company") is pleased to report operating and financial results for the fourth quarter and the 2012 fiscal year. Peyto grew production and reserves per share to record levels in 2012 while delivering a 76% operating margin[1] and a 23% profit margin[2]. An 8% return on capital and an 8% return on equity were achieved despite historically low natural gas prices. Highlights for 2012 include:

- **Production per share up 17%.** *Annual production increased 26% or 17% per share to 267 MMCFe/d (44,527 boe/d) in 2012 from 213 MMCFe/d (35,465 boe/d) in 2011. Q4 2012 production was also up 26% to 49,754 boe/d.*

- **Reserves per share up 15%.** *Proved Producing ("PP"), Total Proved ("TP") and Proved plus Probable Additional ("P+P") reserves increased 24%, 23%, and 22% (15%, 14%, and 13% per share) to 0.9, 1.7, and 2.4 TCFe, respectively.*

- **Reduced cash costs 22%.** *Royalties, operating costs, transportation, G&A and interest expense totaled $1.05/MCFe ($6.30/boe) in 2012 down from $1.35/MCFe ($8.10/boe) in 2011. Industry leading operating costs were just $0.32/MCFe ($1.92/boe) in 2012.*

- **Funds from Operations per share of $2.19.** *Generated $309 million in Funds from Operations ("FFO") in 2012, down 7% from $2.36/share in 2011 despite a 27% drop in realized commodity prices.*

- **Capital investments up 63%.** *Invested a record $452 million to build 25,700 boe/d at a cost of $17,600/boe/d and invested $166 million to acquire Open Range Energy Corp. ("Open Range"), which produced 4,300 boe/d at year end, for a cost of $38,600/boe/d. Average cost to add new production was $20,600/boe/d.*

- **P+P FD&A half the field netback.** *All in FD&A cost for PP, TP and P+P reserves was $2.22/MCFe, $2.04/MCFe and $1.68/MCFe ($10.07/boe), respectively including changes in Future Development Capital ("FDC"), while the average field netback was $3.46/MCFe ($20.75/boe).*

- **NAV per share of $34.** *Net Asset Value or the Net Present Value per share, debt adjusted (discounted at 5%) of the P+P reserves was $20/share of developed reserves and $14/share of undeveloped reserves.*

- **Earnings of $0.67/share and dividends of $0.72/share.** *A total of $94 million in earnings were generated and $102 million in dividends were paid to shareholders. Cumulative dividend/distribution payments made by Peyto to date total $1.3 Billion ($12.31/share).*

2012 in Review

The year 2012 was an historic year for Peyto. With the largest capital program in the Company's history, coupled with its first major corporate acquisition, Peyto added a record 30,000 boe/d of new production. Peyto again led the industry as the lowest cost producer and with this advantage was able to generate a 23% profit margin despite natural gas prices that dropped to their lowest level in Company history. In addition to growing production and reserves per share, Peyto increased its ownership and control of processing infrastructure by 100 mmcf/d or 30%, ensuring this low cost advantage can continue in the future. Peyto's land position in the Alberta Deep Basin also grew by more than 30% resulting in the addition of 1.6 new booked horizontal drilling locations for every well drilled in 2012. Production revenues were maximized with the installation of Peyto's enhanced NGL extraction facilities at the Company's Oldman gas plant. Peyto's profitable, returns driven strategy once again delivered an attractive total return on shareholder's capital in 2012.

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

	3 Months Ended December 31		%	12 Months Ended December 31		%
	2012	2011	Change	**2012**	2011	Change
Operations						
Production						
Natural gas (mcf/d)	**266,808**	212,715	*25%*	**238,490**	189,653	*26%*
Oil & NGLs (bbl/d)	**5,286**	3,947	*34%*	**4,778**	3,856	*24%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**298,522**	236,394	*26%*	**267,160**	212,789	*26%*
Barrels of oil equivalent (boe/d @ 6:1)	**49,754**	39,399	*26%*	**44,527**	35,465	*26%*
Product prices						
Natural gas ($/mcf)	**3.45**	4.21	*(18)%*	**3.23**	4.47	*(28)%*
Oil & NGLs ($/bbl)	**73.01**	88.04	*(17)%*	**73.92**	81.67	*(9)%*
Operating expenses ($/mcfe)	**0.31**	0.35	*(11)%*	**0.32**	0.35	*(9)%*
Transportation ($/mcfe)	**0.11**	0.12	*(8)%*	**0.12**	0.13	*(8)%*
Field netback ($/mcfe)	**3.62**	4.32	*(16)%*	**3.46**	4.46	*(22)%*
General & administrative expenses ($/mcfe)	**0.02**	0.05	*(60)%*	**0.04**	0.06	*(33)%*
Interest expense ($/mcfe)	**0.32**	0.35	*(9)%*	**0.26**	0.28	*(7)%*
Financial ($000, except per share)						
Revenue	**120,310**	114,263	*5%*	**411,400**	424,560	*(3)%*
Royalties	**9,205**	9,870	*(7)%*	**30,754**	41,064	*(25)%*
Funds from operations	**90,078**	80,410	*12%*	**308,865**	314,622	*(2)%*
Funds from operations per share	**0.62**	0.60	*3%*	**2.19**	2.36	*(7)%*
Total dividends	**26,178**	24,245	*8%*	**101,593**	96,068	*6%*
Total dividends per share	**0.18**	0.18	-	**0.72**	0.72	-
Payout ratio (%)	**28**	30	*(7)%*	**33**	31	*6%*
Earnings	**25,823**	26,036	*(1)%*	**93,951**	128,183	*(27)%*
Earnings per share	**0.18**	0.19	*(5)%*	**0.67**	0.96	*(30)%*
Capital expenditures	**156,847**	94,688	*66%*	**617,985**	379,061	*63%*
Weighted average shares outstanding	**145,449,651**	133,913,301	*9%*	**141,093,829**	133,196,301	*6%*
As at December 31						
Net debt (before future compensation expense and unrealized hedging gains)				**662,461**	465,391	*42%*
Shareholders' equity				**1,210,067**	1,015,708	*19%*
Total assets				**2,203,524**	1,800,252	*22%*

	3 Months Ended December 31		12 Months Ended December 31	
($000)	**2012**	2011	**2012**	2011
Cash flows from operating activities	**78,878**	85,592	**284,309**	289,995
Change in non-cash working capital	**4,457**	(19,139)	**12,920**	3,085
Change in provision for performance based compensation	**(7,712)**	(8,739)	**(2,819)**	(1,154)
Income tax paid on account of 2003 reassessment	**1,868**	-	**1,868**	-
Performance based compensation	**12,587**	22,696	**12,587**	22,696
Funds from operations	**90,078**	80,410	**308,865**	314,622
Funds from operations per share	**0.62**	0.60	**2.19**	2.36

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

The Peyto Strategy

The Peyto strategy has long been one of building enduring shareholder value by focusing on generating the maximum possible returns on invested capital. This disciplined model has been tested during times of high commodity prices and record industry activity levels as well as low commodity prices and low activity levels. As with any commodity business, a focus on keeping costs low at all times yields significant advantages over the competition and contributes to generating the best return on the capital invested. Peyto has successfully executed this strategy, aggressively investing capital during opportunistic periods in the cycle while at other times restricting investment, but at all times focusing on cost control. In total, over $2.9 billion has been invested in developing producing reserves that to date have sold for over 1.75 times the total average cost to develop and produce them. The following table illustrates the profitability of the Peyto strategy with the average sales price far exceeding Peyto's historic costs of development and production.

($/Mcfe)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	**2012**
Sales Price	$4.78	$7.21	$7.32	$8.87	$8.76	$8.93	$9.54	$6.75	$6.15	$5.47	**$4.21**
Cost to develop[1]	($0.84)	($1.33)	($1.60)	($2.39)	($2.95)	($2.11)	($2.88)	($2.26)	($2.10)	($2.12)	**($2.22)**
Cost to produce[2]	($1.59)	($2.16)	($2.21)	($2.76)	($2.66)	($2.75)	($3.01)	($1.75)	($1.63)	($1.35)	**($1.05)**
"Profit"	**$2.35**	**$3.72**	**$3.51**	**$3.72**	**$3.15**	**$4.07**	**$3.65**	**$2.74**	**$2.42**	**$2.00**	**$0.94**
Payout		$1.36	$2.28	$2.81	$3.47	$3.92	$4.25	$4.03	$3.37	$1.24	**$1.04**

1. Cost to develop is the PDP FD&A

2. Cost to produce is the total cash costs including Royalties, Operating costs, Transportation, G&A and Interest.

3. Payout is the annual distribution or dividend in $/mcfe of production.

In total, over $1.3 billion in profit has been returned to shareholders. As illustrated above, these payments have come from the ongoing profitable development and production of reserves. The success and sustainability of the Peyto strategy continues to be evident.

Capital Expenditures

Peyto deployed a record amount of capital in 2012, with an exploration and development program comprising $452 million and a corporate acquisition costing $166 million, after associated dispositions.

The 2012 exploration and development program was 19% larger than the 2011 program making it the largest in the Company's 14 year history. In total, $338 million was invested into the drilling and completion of 86 gross (76 net) horizontal wells, while $47 million was invested into pipelines and wellsite equipment to bring those wells on production. An additional $11 million was invested into expanding Peyto's natural gas processing capacity while $26 million was invested in the Oldman plant enhanced liquids extraction facility.

Peyto spent $29 million adding to its extensive inventory of profitable, high quality drilling locations with a minor property acquisition in the Sundance area and the successful purchase of 72 new sections of crown land at an average price of $232/acre.

On August 14, 2012, Peyto closed the acquisition of Open Range for an effective total capital cost of $187.2 million. The acquisition was conducted pursuant to a plan of arrangement with Peyto exchanging 0.0723 Peyto shares for each Open Range share (5.4 million Peyto shares total) and assuming $75 million in net debt (inclusive of transaction costs). On December 1, 2012, Peyto disposed of some minor non-core Open Range assets in the Waskahigan area for total proceeds of $20.9 million, which effectively reduced the cost of the acquisition to $166.3 million.

The following table summarizes the increased capital expenditures for the fourth quarter and 2012 year.

($000)	Three Months ended Dec. 31 **2012**	2011	Twelve Months ended Dec. 31 **2012**	2011
Land	**5,206**	5,910	**10,770**	21,002
Seismic	**612**	1,245	**1,741**	2,859
Drilling – Exploratory & Development	**123,778**	77,570	**337,988**	279,446
Production Equipment, Facilities & Pipelines	**48,015**	10,644	**84,482**	72,079
Acquisition of Open Range Energy Corp.	**-**	-	**187,187**	-
Property Acquisitions	**75**	527	**17,841**	5,581
Dispositions	**(16,969)**	(1,208)	**(17,646)**	(1,906)
(Gains) Losses on Dispositions	**(3,870)**	(1,126)	**(4,378)**	(1,634)
Total Capital Expenditures	**156,847**	93,562	**617,985**	377,427

Reserves

Peyto was successful growing reserves and values in all categories in 2012. The following table illustrates the change in reserve volumes and Net Present Value ("NPV") of future cash flows, discounted at 5%, before income tax and using forecast pricing.

	As at December 31 **2012**	2011	% Change	% Change, debt adjusted per share†
Reserves (BCFe)				
Proved Producing	**945**	765	*24%*	*10%*
Total Proved	**1,659**	1,352	*23%*	*9%*
Proved + Probable Additional	**2,353**	1,935	*22%*	*8%*
Net Present Value ($millions) Discounted at 5%				
Proved Producing	**$2,806**	$2,624	*7%*	*-8%*
Total Proved	**$4,166**	$3,972	*5%*	*-7%*
Proved + Probable Additional	**$5,732**	$5,484	*5%*	*-6%*

†Per share reserves are adjusted for changes in net debt by converting debt to equity using the Dec 31 share price of $22.99 for 2012 and share price of $24.39 for 2011. Net Present Values are adjusted for debt by subtracting net debt from the value prior to calculating per share amounts.
Note: based on the InSite Petroleum Consultants ("InSite") report effective December 31, 2012. The InSite price forecast is available at www.InSitepc.com. For more information on Peyto's reserves, refer to the Press Releases dated February 13, 2013 and February 14, 2013 announcing the 2012 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 2013.

Performance Ratios

The following table highlights additional annual performance indicators, to be used for comparative purposes, but it is cautioned that in isolation they do not measure investment success.

	2012	**2011**	**2010**	**2009**	**2008**	**2007**
Proved Producing						
FD&A ($/mcfe)	**$2.22**	$2.12	$2.10	$2.26	$2.88	$2.11
RLI (yrs)	**9**	9	11	14	14	13
Recycle Ratio	**1.6**	1.9	2.0	1.8	2.3	2.8
Reserve Replacement	**284%**	230%	239%	79%	110%	127%

Total Proved						
FD&A ($/mcfe)	**$2.04**	$2.13	$2.35	$1.73	$3.17	$1.57
RLI (yrs)	**15**	16	17	21	17	16
Recycle Ratio	**1.7**	1.9	1.8	2.3	2.1	3.7
Reserve Replacement	**414%**	452%	456%	422%	139%	175%
Future Development Capital ($MM)	**$1,318**	$1,111	$741	$446	$222	$169
Proved plus Probable Additional						
FD&A ($/mcfe)	**$1.68**	$1.90	$2.19	$1.47	$3.88	$1.56
RLI (yrs)	**22**	22	25	29	23	21
Recycle Ratio	**2.1**	2.1	1.9	2.8	1.7	3.7
Reserve Replacement	**527%**	585%	790%	597%	122%	117%
Future Development Capital ($MM)	**$2,041**	$1,794	$1,310	$672	$390	$321

- 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 ($618+$207)/(1,659-1,352+98) = $2.04/mcfe or $12.24/boe).

- The reserve life index (RLI) is calculated by dividing the reserves (in boes) in each category by the annualized average production rate in boe/year (eg. Proved Producing 157,491/(49.754x365) = 8.7). 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. In Peyto's opinion, for comparative purposes, the proved developed producing reserve life provides the best measure of sustainability.

- The Recycle Ratio is calculated by dividing the field netback per MCFe, before hedging, by the FD&A costs for the period (eg. Proved Producing (($3.46)/$2.22=1.6). The recycle ratio is comparing the netback from existing reserves to the cost of finding new reserves and may not accurately indicate investment success unless the replacement reserves are of equivalent quality as the produced reserves.

- The reserve replacement ratio is determined by dividing the yearly change in reserves before production by the actual annual production for the year (eg. Total Proved ((1,659-1,352+98)/98) = 4.14).

Value Creation/Reconciliation

In order to measure the success of all of the capital invested in 2012, it is necessary to quantify the total amount of value added during the year and compare that to the total amount of capital invested. As requested, Insite has run last year's reserve evaluation with this year's price forecast to remove the change in value attributable to both commodity prices and changing royalties. This approach isolates the value created by the Peyto team from the value created (or lost) by those changes outside of their control. Since the capital investments in 2012 were funded from a combination of cash flow, debt and equity, it is necessary to include the change in debt and the change in shares outstanding to determine if the change in value is truly accretive to shareholders.

At year end 2012, Peyto's estimated net debt had increased by $196.8 million to $662.4 million while the number of shares outstanding had increased by 10.3 million shares to 148.7 million shares. The change in debt includes all of the capital expenditures, as well as acquisitions, 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 $963 million of Proved Producing, $1.36 billion of Total Proved, and $2.0 billion of Proved plus Probable Additional undiscounted reserve value, with a $618 million capital investment. The ratio of value creation to capital expenditure 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 2012, the Proved Producing NPV recycle ratio is 1.6. Refer to the value reconciliation table in the February 14, 2013 Reserve Press Release for additional details on the value creation determination.

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 and reconciliation presented above is the best determination of profitability as it compares the value of what was created relative to what was invested. 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 2012, the Proved Producing

NPV recycle ratio was 1.6 times. This means for each dollar invested, the Peyto team was able to create 1.6 new dollars of Proved Producing reserve value. The average NPV Recycle Ratio over the last 5 years is 3.0 times for undiscounted future values or 2.2 times for future values discounted at 10%. The historic NPV recycle ratios are presented in the following table.

Value Creation	**Dec 31, 2012**	Dec 31, 2011	Dec 31, 2010	Dec 31, 2009	Dec 31, 2008	Dec 31, 2007	Dec 31, 2006
NPV_0 Recycle Ratio							
Proved Producing	**1.6**	2.4	3.5	5.4	2.1	4.7	2.9
Total Proved	**2.2**	4.7	6.1	18.9	2.5	5.5	2.9
Proved + Probable Additional	**3.2**	6.6	10.3	27.1	2.2	3.8	3.8

- NPV_0 (net present value) recycle ratio is calculated by dividing the undiscounted NPV of reserves added in the year by the total capital cost for the period (eg. Proved Producing ($963/$618) = 1.6).

Quarterly Review

Activity in the fourth quarter of 2012 included the drilling of 28 gross (27.2 net) horizontal wells, the completion of 33 gross (29.6 net) wells and the installation of wellsite equipment and tie in of 34 gross (30.4 net) wells. Capital expenditures in Q4 totaled $156.8 million with $78 million spent on drilling, $47 million on completions, and $22 million on wellsite equipment and pipelines. Installation of the enhanced liquids extraction facilities at the Oldman gas plant was responsible for the majority of the $25 million invested in facilities. In the quarter, 30.5 sections of new land was purchased at crown land sales for $5.2 million or $267/ac.

On December 1, 2012 Peyto disposed of some minor non-core Open Range assets in the Waskahigan area for total proceeds of $20.9 million reflected in the previous capital summary as a disposition and gain on disposition.

Production for Q4 2012 was up 26% from Q4 2011 to 49,754 boe/d including 299 mmcf/d of natural gas and 5,286 bbl/d of oil and natural gas liquids. Fourth quarter production was less than expected, however, due to an unanticipated outage at Peyto's Oldman gas processing facility. The cause of the outage was a faulty piece of equipment installed during the new Oldman Deep Cut plant expansion. The defective equipment prevented the operation of approximately two thirds, or 80 mmcf/d, of the processing capacity at the facility. This equipment has been repaired and the impacted processing capacity was brought back online on January 7, 2013 with the Deep Cut plant operation commencing January 25, 2013. Approximately 10,700 boe/d of net production was offline for the final 13 days in December.

Peyto's natural gas price in the fourth quarter 2012 of $3.45/mcf was 18% lower than the previous year, while the realized oil and natural gas liquids price of $73.01/bbl was 17% lower. These prices combined for a realized price of $4.38/mcfe including $0.13/mcfe of realized hedging gain. Q4 2012 total cash costs of $1.10/mcfe included $0.34/mcfe for royalties, $0.31/mcfe for operating costs, $0.11/mcfe for transportation, $0.02/mcfe for G&A and $0.32/mcfe for interest. Realized prices less cash costs resulted in cash netbacks for the quarter of $3.28/mcfe or a 75% operating margin.

Peyto incurred a one-time tax charge of $1.9 million or $0.12/mcfe in the quarter due to the reassessment of Peyto's 2003 Alberta income tax return. The reassessment related to the treatment of the payout of stock options for income tax purposes upon conversion to an income trust in 2003. The federal reassessment was paid to Canada Revenue Agency in 2008, however, the Alberta Government subsequently reassessed the 2003 Alberta income tax return in January, 2013 which was paid in the same month and accrued as a one-time charge in the 2012 financial results.

Marketing

The current natural gas price outlook is substantially better than this time last year. Although storage volumes are at the high end of historical levels, growing demand and flat to declining North American natural gas supply is supporting prices at $3.00/GJ CND$ and $3.50/MMBTU US$. With current supplies matching demand, weather should continue to play a significant role in future prices. In addition, natural gas is playing an increasing role for summer power generation, particularly in light of the current projections for decreased hydro power this coming spring and ongoing retirement of coal fired power plants.

Natural gas liquids prices have, in general, remained substantially higher than the equivalent price in gaseous form. Recent industry trends to extract more Propane and Ethane from the natural gas production have increase supplies and filled available liquefied petroleum gas ("LPG") fractionation plant capacity. This has put significant downward pressure on the price for these specific products which will likely continue for the near future. The majority of Peyto's LPG is under long term contract for transportation and fractionation.

Approximately 50% of Peyto's natural gas production in the fourth quarter had been pre-sold in forward sales done over the previous year at an average price of $3.17/GJ. The remaining balance of production was subject to AECO monthly spot prices that averaged $2.90/GJ. On a blended basis, Peyto's realized gas price was $3.04/GJ or $3.45/mcf, reflective of Peyto's high heat content natural gas production.

The Company's hedging practice of layering in future sales in the form of fixed price swaps, in order to smooth out the volatility in natural gas price, continued throughout the quarter and into 2013. The following table summarizes the remaining hedged volumes and prices for the upcoming years, effective March 6, 2013:

	Future Sales		Average Price (CAD)	
	GJ	Mcf	$/GJ	$/Mcf
2013	54,842,500	46,873,932	$3.20	$3.74
2014	27,575,000	23,568,376	$3.24	$3.79
Total	82,417,500	70,442,308	$3.21	$3.76

As illustrated in the following table, Peyto's annual realized natural gas liquids prices(1) were approximately 10% lower on a year over year basis, due primarily to realized Propane prices which were 45% lower than the price realized in 2011.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2012	2011	**2012**	2011
Condensate ($/bbl)	**91.22**	101.08	**94.78**	94.47
Propane ($/bbl)	**25.58**	46.03	**24.12**	44.00
Butane ($/bbl)	**63.38**	67.46	**64.05**	63.41
Pentane ($/bbl)	**94.34**	104.03	**98.93**	96.63

(1) Liquids prices are Peyto realized prices in Canadian dollars adjusted for fractionation and transportation.

Peyto's hedging practice with respect to propane and butane also continued throughout the fourth quarter. The following table summarizes the hedged volumes and prices for the upcoming years, effective March 6, 2013.

	Propane		Butane	
	Future Sales (bbls)	Average Price ($USD/bbl)	Future Sales (bbls)	Average Price ($USD/bbl)
2013	213,972	$33.95	15,345	$65.88

Activity Update

Peyto has continued its record level of activity into the first quarter of 2013. Nine rigs are drilling and four completions crews are following behind the drilling rigs. To the end of February, 17 gross (16.9 net) wells have been rig released and 14 gross (13.2 net) wells have been brought on production.

Current production is approximately 57,000 boe/d which includes 4,300 boe/d of new additions since early January. Over 5,000 boe/d of production awaits tie-in of 8.0 net wells that have been completed but are not yet onstream.

Over the first two months of 2013, two compressor expansion projects were completed. An additional 10 MMcf/d of compression was added to the Nosehill Plant taking the facility capacity to 120 MMcf/d. In addition, another 10 MMcf/d of compression was added to the Wildhay Plant taking it to a capacity of 70 MMcf/d.

Three plant construction projects are in the early stage of equipment fabrication with field work anticipated for the summer of 2013 and start-ups ranging from late summer to fall. The first project is a 30 MMcf/d addition to the Swanson Plant (taking it to 60 MMcf/d) for the accommodation of Ansell area growth volumes. In addition to the plant expansion, a 50 km strategic pipeline from Ansell to Swanson is currently under construction with targeted completion after breakup. The second project is a new Oldman North Plant to be located adjacent to the existing 125 MMcf/d Oldman Plant and initially designed for 40 MMcf/d. This plant will handle ongoing Cardium and Falher horizontal well development. A third new facility is planned for mid-fall for a new step-out area of Wilrich development that is presently undergoing early stage delineation drilling.

The Oldman Deep Cut facility built at the end of 2012 was successfully brought online in mid-January. The plant is currently running just below its 80 MMcfd raw gas capacity as some final re-compression tuning occurs for the four new compressors. The overall Oldman LPG recovery level has increased from a pre-Deep Cut level of 1,600 bbl/d to a present level of 2,400 bbl/d at the current -75°C operating level for the Deep Cut train. With continued tuning of the re-compression, throughput will be brought up and chilling will be dropped towards the -80°C design level to realize the full 2,600 bbl/d of LPG.

As in most past years, Peyto tentatively plans to shut down its drilling operations over spring break-up which is contemplated to occur from early April to mid-May and resume its drilling program with nine rigs. Post break-up drilling will focus in the traditional Greater Sundance area with volumes filling the new Oldman North Plant, the Ansell area with volumes pipelined to the expanded Swanson Plant, and with some additional Northern Cardium drilling. The $450 to $500 million capital program is on pace and it is expected that target 2013 exit production levels of 62,000 to 67,000 boe/d will be reached.

2013 Outlook

2013 is forecast to be the most active in the Company's history. It also comes at a time when the majority of natural gas producers in North America are challenged by low natural gas prices and high costs, rendering many plays uneconomic. Over its history, Peyto has maintained a unique low cost advantage that allows the Company to profitably grow its asset base, despite lower commodity prices, taking advantage of lower service and material costs. In effect, Peyto can be "greedy when others are fearful" and capture new opportunities when others are cutting capital budgets and rationalizing assets. This prevailing economic condition is forecast to continue throughout 2013 allowing Peyto the opportunity to deliver the same superior total returns to shareholders as in the past. Peyto's expertise in the Alberta Deep Basin will serve it well in this regard. The company's financial flexibility, quality asset base and strong balance sheet position Peyto to continue to be opportunistic. As always, capital investments will only be pursued if Peyto's high return objectives can be met.

Conference Call and Webcast

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2012 fourth quarter and full year financial results on Thursday, March 7th, 2013, at 9:00 a.m. Mountain Standard Time (MST), or 11:00 a.m. Eastern Standard Time (EST). To participate, please call 1-416-340-8530 (Toronto area) or 1-877-440-9795 for all other participants. The conference call will also be available on replay by calling 1-905-694-9451 (Toronto area) or 1-800-408-3053 for all other parties, using passcode 9284446. The replay will be available at 11:00 a.m. MST, 1:00 p.m. EST Thursday, March 7th, 2013 until midnight EDT on Thursday, March 14th, 2013. The conference call can also be accessed through the internet at http://events.digitalmedia.telus.com/peyto/030713/index.php. After this time the conference call will be archived on the Peyto Exploration & Development website at www.peyto.com .

Management's Discussion and Analysis

A copy of the fourth quarter report to shareholders, including the MD&A, and audited financial statements and related notes is available at http://www.peyto.com/news/Q42012MDandA.pdf and will be filed at SEDAR, www.sedar.com , at a later date.

Annual General Meeting

Peyto's Annual General Meeting of Shareholders is scheduled for 3:00 p.m. on Wednesday, June 5, 2013 at Livingston Place Conference Centre, +15 level, 222-3rd Avenue SW, Calgary, Alberta. Shareholders are encouraged to visit the Peyto website at www.peyto.com where there is a wealth of information designed to inform and educate investors. A monthly President's Report can also be found on the website which follows the progress of the capital program and the ensuing production growth, along with video and audio commentary from Peyto's senior management.

Darren Gee
President and CEO
March 6, 2013

Certain information set forth in this document and Management's Discussion and Analysis, including management's assessment of Peyto's future plans and operations, contains forward-looking statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the timing of its enhanced liquids extraction project and guidance as to the capital expenditure plans of Peyto under the heading "2013 Outlook". By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond these parties' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Peyto's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Peyto will derive therefrom.

Peyto Exploration & Development Corp.

Consolidated Balance Sheet

(Amount in $ thousands)

	December 31 2012	December 31 2011
Assets		
Current assets		
Cash	-	57,224
Accounts receivable	85,677	53,829
Due from private placement *(Note 7)*	3,459	9,740
Derivative financial instruments *(Note 13)*	10,254	38,530
Prepaid expenses	4,150	3,991
	103,540	163,314
Long-term derivative financial instruments *(Note 13)*	-	6,304
Prepaid capital	3,714	1,414
Property, plant and equipment, net *(Note 4)*	2,096,270	1,629,220
	2,099,984	1,636,938
	2,203,524	1,800,252
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	164,946	110,483
Current income tax	1,890	-
Dividends payable *(Note 7)*	8,911	8,278
Provision for future performance based compensation *(Note 11)*	2,677	4,321
	178,424	123,082
Long-term debt *(Note 5)*	580,000	470,000
Long-term derivative financial instruments *(Note 13)*	2,532	-
Provision for future performance based compensation *(Note 11)*	59	1,235
Decommissioning provision *(Note 6)*	58,201	38,037
Deferred income taxes *(Note 12)*	174,241	152,190
	815,033	661,462
Shareholders' equity		
Shareholders’ capital *(Note 7)*	1,124,382	889,115
Shares to be issued *(Note 7)*	3,459	9,740
Retained earnings	75,247	82,889
Accumulated other comprehensive income *(Note 7)*	6,979	33,964
	1,210,067	1,015,708
	2,203,524	1,800,252

Approved by the Board of Directors

(signed) *“Michael MacBean”*
Director

(signed) *“Darren Gee”*
Director

Peyto Exploration & Development Corp.
Consolidated Income Statement
(Amount in $ thousands)

	Year ended December 31	
	2012	**2011**
Revenue		
Oil and gas sales	357,734	387,240
Realized gain on hedges *(Note 13)*	53,667	37,320
Royalties	(30,754)	(41,064)
Petroleum and natural gas sales, net	**380,647**	383,496
Expenses		
Operating *(Note 8)*	31,260	27,379
Transportation	11,275	9,754
General and administrative *(Note 9)*	3,846	4,911
Market and reserves based bonus *(Note 11)*	12,587	22,696
Future performance based compensation *(Note 11)*	(2,819)	(1,154)
Interest *(Note 10)*	25,401	21,881
Accretion of decommissioning provision *(Note 10)*	1,044	840
Depletion and depreciation *(Note 4)*	172,338	130,678
Gain on disposition of assets *(Note 4)*	(4,378)	(1,634)
	250,554	215,351
Earnings before taxes	**130,093**	168,145
Income tax		
Deferred income tax expense (recovery) *(Note 12)*	34,274	35,013
Income tax expense *(Note 12)*	1,868	4,949
Earnings for the year	**93,951**	128,183
Earnings per share *(Note 7)*		
Basic and diluted	**$ 0.67**	$ 0.96
Weighted average number of common shares outstanding *(Note 7)*		
Basic and diluted	**141,093,829**	133,196,103

Peyto Exploration & Development Corp.

Consolidated Statement of Comprehensive Income

(Amount in $ thousands)

	Year ended December 31	
	2012	**2011**
Earnings for the year	**93,951**	128,183
Other comprehensive income		
Change in unrealized gain (loss) on cash flow hedges	17,687	54,243
Deferred tax recovery (expense)	8,995	(3,852)
Realized gain on cash flow hedges	(53,667)	(37,320)
Comprehensive Income	**66,966**	141,254

Peyto Exploration & Development Corp.

Consolidated Statement of Changes in Equity

(Amount in $ thousands)

	Year ended December 31	
	2012	**2011**
Shareholders' capital, Beginning of Year	**889,115**	755,831
Common shares issued	115,024	115,126
Common shares issued pursuant to acquisition of Open Range Energy Corp.	112,187	-
Common shares issued by private placement	11,952	17,150
Common shares issuance costs (net of tax)	(3,896)	(3,854)
Common shares issued pursuant to DRIP	-	1,973
Common shares issued pursuant to OTUPP	-	2,889
Shareholders' capital, End of Year	**1,124,382**	889,115

Common shares to be issued, Beginning of Year	**9,740**	17,285
Common shares issued	(9,740)	(17,285)
Common shares to be issued	3,459	9,740
Common shares to be issued, End of Year	**3,459**	9,740

Retained earnings, Beginning of Year	**82,889**	50,774
Earnings for the year	93,951	128,183
Dividends *(Note 7)*	(101,593)	(96,068)
Retained earnings, End of Year	**75,247**	82,889

Accumulated other comprehensive income, Beginning of Year	**33,964**	20,893
Other comprehensive income (loss)	(26,985)	13,071
Accumulated other comprehensive income, End of Year	**6,979**	33,964

Total Shareholders' Equity	**1,210,067**	1,015,708

Peyto Exploration & Development Corp.

Consolidated Statement of Cash Flows

(Amount in $ thousands)

	Year ended December 31 2012	2011
Cash provided by (used in)		
Operating activities		
Earnings	93,951	128,183
Items not requiring cash:		
Deferred income tax	34,274	35,013
Gain on disposition of assets	(4,378)	(1,634)
Depletion and depreciation	172,338	130,678
Accretion of decommissioning provision	1,044	840
Change in non-cash working capital related to operating activities	(12,920)	(3,085)
	284,309	289,995
Financing activities		
Issuance of common shares	126,976	132,276
Issuance costs	(5,195)	(5,137)
Dividends	(100,960)	(103,615)
Increase (decrease) in bank debt	(40,000)	115,000
Repayment of Open Range bank debt	(72,000)	-
Issuance of long term notes	150,000	-
	58,821	138,524
Investing activities		
Additions to property, plant and equipment	(400,354)	(382,189)
Dispositions of property, plant and equipment	-	3,000
	(400,354)	(379,189)
Net increase in cash	(57,224)	49,330
Cash, beginning of year	57,224	7,894
Cash, end of year	**-**	57,224

The following amounts are included in Cash flows from operating activities:

Cash interest paid	23,460	19,656
Cash taxes paid	-	-

1. Nature of operations

Peyto Exploration & Development Corp. and its wholly owned subsidiary Open Range Energy Corp. (“Open Range”), (collectively “Peyto” or the “Company”) are Calgary based oil and natural gas companies. Peyto and Open Range amalgamated on January 1, 2013. Peyto conducts exploration, development and production activities in Canada. Peyto is incorporated and domiciled in the Province of Alberta, Canada. The address of its registered office is 1500, 250 – 2nd Street SW, Calgary, Alberta, Canada, T2P 0C1.

These financial statements were approved and authorized for issuance by the Board of Directors of Peyto on March 5, 2013.

2. Basis of presentation

These consolidated financial statements (“financial statements”) for the years ended December 31, 2012 and December 31, 2011 represent the Company’s results and financial position in accordance with International Financial Reporting Standards (“IFRS”). The consolidated financial statements include the accounts of Peyto Exploration & Development Corp. and its subsidiary. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies to obtain benefits from their activities. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

a) Summary of significant accounting policies

The precise determination of many assets and liabilities is dependent upon future events and the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The financial statements have, in management’s opinion, been properly prepared within reasonable limits of materiality and within the framework of the Company’s basis of presentation as disclosed.

b) Significant accounting estimates and judgements

The timely preparation of the financial statements in conformity with IFRS 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 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 financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, decommissioning costs and obligations and amounts used for impairment calculations are based on estimates of gross proved plus probable 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 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 Company operates are subject to change. As such, income taxes are subject to measurement uncertainty.

c) Presentation currency

All amounts in these financial statements are expressed in Canadian dollars, as this is the functional and presentation currency of the Company.

d) Cash Equivalents

Cash equivalents include term deposits or a similar type of instrument, with a maturity of three months or less when purchased.

e) Jointly controlled assets

A jointly controlled asset involves joint control and offers joint ownership by the Company and other partners of assets contributed to or acquired for the purpose of the jointly controlled assets, without the formation of a corporation, partnership or other entity.

The Company accounts for its share of the jointly controlled assets, any liabilities it has incurred, its share of any liabilities jointly incurred with its partners, income from the sale or use of its share of the joint asset's output, together with its share of the expenses incurred by the jointly controlled asset and any expenses it incurs in relation to its interest in the jointly controlled asset.

f) Exploration and evaluation assets

Pre-license costs

Costs incurred prior to obtaining the legal right to explore for hydrocarbon resources are expensed in the period in which they are incurred. The Company has no pre-license costs.

Exploration and evaluation costs

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as exploration and evaluation intangible assets until the drilling of the well is complete and the results have been evaluated. All such costs are subject to technical feasibility, commercial viability and management review as well as review for impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. The Company has no exploration or evaluation assets.

g) Property, plant and equipment

Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning provision and borrowing costs for qualifying assets. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Costs include expenditures on the construction, installation or completion of infrastructure such as well sites, pipelines and facilities including activities such as drilling, completion and tie-in costs, equipment and installation costs, associated geological and human resource costs, including unsuccessful development or delineation wells.

Oil and natural gas asset swaps

For exchanges or parts of exchanges that involve assets, the exchange is accounted for at fair value. Assets are then de-recognized at their current carrying amount.

Depletion and depreciation

Oil and natural gas properties are depleted on a unit-of-production basis over the proved plus probable reserves. All costs related to oil and natural gas properties (net of salvage value) and estimated costs of future development of proved plus probable undeveloped reserves are depleted and depreciated using the unit-of-production method based on estimated gross proved plus probable reserves as determined by independent reservoir 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.

Other property, plant and equipment are depreciated using a declining balance method over useful life of 20 years.

h) Corporate assets

Corporate assets not related to oil and natural gas exploration and development activities are recorded at historical costs and depreciated over their useful life. These assets are not significant or material in nature.

i) Impairment of non-financial assets

The Company assesses at each reporting date whether there is an indication that an asset may be impaired. If any indication exists, or when annual impairment testing for an asset is required, the Company estimates the asset's recoverable amount. An asset's recoverable amount is the higher of fair value less costs to sell or value-in-use and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, in which case the recoverable amount is assessed as part of a cash generating unit ("CGU"). If the carrying amount of an asset or CGU exceeds its recoverable amount, the asset or CGU is considered impaired and is written down to its recoverable amount. In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs to sell, recent market transactions are taken into account, if available. If no such transactions can be identified, an appropriate valuation model is used. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded securities or other available fair value indicators.

Impairment losses of continuing operations are recognized in the income statement.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the Company estimates the asset's or cash-generating unit's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

j) Leases

Leases or other arrangements entered into for the use of an asset are classified as either finance or operating leases. Finance leases transfer to the Company substantially all of the risks and benefits incidental to ownership of the leased asset. Assets under finance lease are amortized over the shorter of the estimated useful life of the assets and the lease term. All other leases are classified as operating leases and the payments are amortized on a straight-line basis over the lease term.

k) Financial instruments

Financial instruments within the scope of IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39") are initially recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: "fair value through profit or loss"; "loans & receivables"; and "other liabilities". Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on fair value through profit or loss financial instruments are recognized in earnings. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method. The Company has made the following classifications:

Financial Assets & Liabilities	**Category**
Cash	Fair value through profit or loss
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
Dividends Payable	Other liabilities
Long Term Debt	Other liabilities
Derivative Financial Instruments	Fair value through profit or loss

Derivative instruments and risk management

Derivative instruments are utilized by the Company to manage market risk against volatility in commodity prices. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company has chosen to designate its existing derivative instruments as cash flow hedges. The Company assesses, on an ongoing basis, whether the derivatives that are used as cash flow hedges are highly effective in offsetting changes in cash flows of hedged items. All derivative instruments are recorded on the balance sheet at their fair value. The effective portion of the gains and losses is recorded in other comprehensive income until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the income statement, 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 Company has no contracts containing embedded derivatives.

Normal purchase or sale exemption
Contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements fall within the exemption from IAS 32 *Financial Instruments: Presentation* ("IAS 32") and IAS 39, which is known as the 'normal purchase or sale exemption'. The Company recognizes such contracts in its balance sheet only when one of the parties meets its obligation under the contract to deliver either cash or a non-financial asset.

l) Hedging
The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. All derivative financial instruments are initiated within the guidelines of the Company'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 Company 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 revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. 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.

m) Inventories
Inventories are stated at the lower of cost and net realizable value. Cost of producing oil and natural gas is accounted on a weighted average basis. This cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition.

n) Provisions

General
Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Company expects some or all of a provision to be reimbursed, the reimbursement is recognized as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as a finance cost.

Decommissioning provision
Decommissioning provision is recognized when the Company has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. A corresponding amount equivalent to the provision is also recognized as part of the cost of the related property, plant and equipment. The amount recognized is the estimated cost of decommissioning, discounted to its present value using a risk-free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The accretion of the discount on the decommissioning provision is included as a finance cost.

o) Taxes

Current income tax
Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, at the reporting date, in Canada.

Current income tax relating to items recognized directly in equity is recognized in equity and not in the income statement. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred income tax

The Company follows the liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantively enacted tax rates expected to apply when the asset is realized or the liability settled. Deferred income tax assets are only recognized to the extent it is probable that sufficient future taxable income will be available to allow the deferred income tax asset to be realized. Accumulated deferred income tax balances are adjusted to reflect changes in income tax rates that are enacted or substantively enacted with the adjustment being recognized in earnings in the period that the change occurs, except for items recognized in shareholders' equity.

p) Revenue recognition

Revenue from the sale of oil, natural gas and natural gas liquids is recognized when the significant risks and rewards of ownership have been transferred, which is when title passes to the purchaser. This generally occurs when product is physically transferred into a pipe or other delivery system.

Gains and losses on disposition

For all dispositions, either through sale or exchange, gains and losses are calculated as the difference between the sale or exchange value in the transaction and the carrying amount of the assets disposed. Gains and losses on disposition are recognized in earnings in the same period as the transaction date.

q) Borrowing costs

Borrowing costs directly relating to the acquisition, construction or production of a qualifying capital project under construction are capitalized and added to the project cost during construction until such time the assets are substantially ready for their intended use, which is, when they are capable of commercial production. Where the funds used to finance a project form part of general borrowings, the amount capitalized is calculated using a weighted average of rates applicable to relevant general borrowings of the Company during the period. All other borrowing costs are recognized in the income statement in the period in which they are incurred.

r) Share-based payments

Liability-settled share-based payments to employees are measured at the fair value of the liability award at the grant date. A liability equal to fair value of the payments is accrued over the vesting period measured at fair value using the Black-Scholes option pricing model.

The fair value determined at the grant date of the liability-settled share-based payments is expensed on a graded basis over the vesting period, based on the Company's estimate of liability instruments that will eventually vest. At the end of each reporting period, the Company revises its estimate of the number of liability instruments expected to vest. The impact of the revision of the original estimates, if any, is recognized in the income statement such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the related liability on the balance sheet.

s) Earnings per share

Basic and diluted earnings per share is computed by dividing the net earnings available to common shareholders by the weighted average number of shares outstanding during the reporting period. The Company has no dilutive instruments outstanding which would cause a difference between the basic and diluted earnings per share.

t) Shareholders' capital

Common shares are classified within Shareholders' equity. Incremental costs directly attributable to the issuance of shares are recognized as a deduction from Shareholders' capital.

u) Standards issued but not yet effective

Peyto has reviewed new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company:

In May 2011, the IASB released the following new standards: IFRS 10, "Consolidated Financial Statements", IFRS 11, "Joint Arrangements", IFRS 12, "Disclosures of Interests in Other Entities" and IFRS 13, "Fair Value Measurement". Each of these standards is to be adopted for fiscal years beginning January 1, 2013 with earlier adoption permitted. A brief description of each new standard follows below:

- IFRS 10, "Consolidated Financial Statements" supercedes IAS 27 "Consolidation and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities". This standard provides a single model to be applied in control analysis for all investees including special purpose entities. The adoption of this standard is not expected to have any impact on Peyto's financial statements.

- IFRS 11, "Joint Arrangements" divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting. The adoption of this standard is not expected to have any impact on Peyto's financial statements.

- IFRS 12, "Disclosure of Interests in Other Entities" combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements as well as unconsolidated structured entities. The adoption of this standard is not expected to have a material impact on Peyto's financial statements.

- IFRS 13, "Fair Value Measurement" defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The adoption of this standard is not expected to have a material impact on Peyto's financial statements.

As of January 1, 2015 , Peyto will be required to adopt IFRS 9 "Financial Instruments", which is the result of the first phase of the International Accounting Standards Board ("IASB") project to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on Peyto's Consolidated Financial Statements will not be known until the project is complete.

3. Corporate Acquisition

On August 14, 2012, Peyto completed the acquisition, by plan of arrangement, of all issued and outstanding common shares of Open Range. The total consideration of approximately $187.2 million was paid for by the issuance of 5.4 million common shares of Peyto and the assumption of Open Range's long-term debt and working capital deficiency ($190.4 million was allocated to Property, plant & equipment). Transaction costs of approximately $0.7 million are included in general and administrative expenses in the Consolidated Income Statement.

Fair value of net assets acquired	
Working capital	(1,868)
Property, plant and equipment	190,385
Financial derivative instruments	(1,132)
Bank debt	(72,000)
Decommissioning provision	(5,127)
Deferred income taxes	1,929
Total net assets acquired	112,187
Consideration	
Shares issued (5,404,007 shares)	112,187
Total purchase price	112,187

The above amounts are estimates, which were made by management at the time of the preparation of these consolidated financial statements based on information then available. Amendments may be made as amounts subject to estimates are finalized.

If Peyto had acquired Open Range on January 1, 2012, the pro-forma results of the oil and gas sales, net income and comprehensive income for the period ended December 31, 2012 would have been as follows;

	As Stated December 31, 2012	**Open Range January 1, 2012 to August 14, 2012**	**Pro Forma December 31, 2012**
Oil and gas sales	380,647	27,756	408,403
Net income	93,951	1,134	95,085
Comprehensive income	66,966	1,134	68,100

4. Property, plant and equipment, net

Cost	
At December 31, 2010	1,452,242
Additions	392,309
Dispositions	(785)
At December 31, 2011	1,843,766
Acquisitions through business combinations	190,385
Additions	466,506
Dispositions	(17,649)
At December 31, 2012	2,483,008
Accumulated depletion and depreciation	
At December 31, 2010	(84,373)
Depletion and depreciation	(130,678)
Dispositions	505
At December 31, 2011	(214,546)
Depletion and depreciation	(172,338)
Dispositions	146
At December 31, 2012	(386,738)
Carrying amount at December 31, 2012	**2,096,270**

Proceeds received for assets disposed of during 2012 were $21.9 million (2011 - $3.0 million).

In September 2012, Peyto acquired producing properties for net proceeds of $16.7 million, which were allocated to property, plant and equipment of $17.4 million and decommissioning liabilities of $0.7 million. The properties are in Peyto's core area of production. The impact on revenue and net income is not significant.

During 2012 Peyto capitalized $7.8 million (2011 - $5.5 million) of general and administrative expense directly attributable to exploration and development activities.

The Company did not have any indicators of impairment in the current or prior years.

5. Long-term debt

	December 31, 2012	December 31, 2011
Bank credit facility	430,000	470,000
Senior secured notes	150,000	-
Balance, end of the year	**580,000**	**470,000**

The Company has a syndicated $730 million extendible revolving credit facility with a stated term date of April 28, 2013. The bank facility is made up of a $30 million working capital sub-tranche and a $700 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 Company, 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 further one year term, at the end of which time the facility would be due and payable. Outstanding amounts on this facility will bear interest at rates ranging from prime plus 1.0% to prime plus 2.5% determined by the Company's 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.

On January 3, 2012, Peyto issued CDN $100 million of senior secured notes pursuant to a note purchase and private shelf agreement. The notes were issued by way of private placement and rank equally with Peyto's obligations under its bank facility. The notes are secured under the General Security Agreement with a floating charge on land registered in Alberta is held as collateral. The notes have a coupon rate of 4.39% and mature on January 3, 2019. Interest will be paid semi-annually in arrears.

On September 6, 2012, Peyto issued CDN $50 million of senior secured notes pursuant to a note purchase and private shelf agreement. The notes were issued by way of private placement and rank equally with Peyto's obligations under its bank facility. The notes are secured under the General Security Agreement with a floating charge on land registered in Alberta is held as collateral. The notes have a coupon rate of 4.88% and mature on September 6, 2022. Interest will be paid semi-annually in arrears.

Upon the issuance of the senior secured notes January 3, 2012, Peyto became subject to the following financial covenants as defined in the credit facility and note purchase and private shelf agreements:

- Senior Debt to EBITDA Ratio will not exceed 3.0 to 1.0
- Total Debt to EBITDA Ratio will not exceed 4.0 to 1.0
- Interest Coverage Ratio will not be less than 3.0 to 1.0
- Total Debt to Capitalization Ratio will not exceed 0.55:1.0

Peyto is in compliance with all financial covenants at December 31, 2012.

Peyto's total borrowing capacity is $880 million and Peyto's net credit facility is $730 million.

The fair value of all senior notes as at December 31, 2012, is $149.9 million compared to a carrying value of $150.0 million.

Total interest expense for 2012 was $25.4 million (2011 - $21.9 million) and the average borrowing rate for 2012 was 4.7% (2011 – 4.8%).

6. Decommissioning provision

The Company makes provision for the future cost of decommissioning wells, pipelines and facilities on a discounted basis based on the commissioning of these assets.

The decommissioning provision represents the present value of the decommissioning costs related to the above infrastructure, which are expected to be incurred over the economic life of the assets. The provisions have been based on the Company's internal estimates on the cost of decommissioning, the discount rate, the inflation rate and the economic life of the infrastructure. Assumptions, based on the current economic environment, have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon the future market prices for the necessary decommissioning work required which will reflect market conditions at the relevant time. Furthermore, the timing of the decommissioning is likely to depend on when production activities ceases to be economically viable. This in turn will depend and be directly related to the current and future commodity prices, which are inherently uncertain.

The following table reconciles the change in decommissioning provision:

Balance, December 31, 2010	**24,734**
New or increased provisions	4,764
Accretion of discount	840
Change in discount rate and estimates	7,699
Balance, December 31, 2011	**38,037**
New or increased provisions	13,908
Accretion of discount	1,044
Change in discount rate and estimates	5,212
Balance, December 31, 2012	**58,201**
Current	-
Non-current	58,201

The Company has estimated the net present value of its total decommissioning provision to be $58.2 million as at December 31, 2012 ($38.0 million at December 31, 2011) based on a total future undiscounted liability of $127.9 million ($101.2 million at December 31, 2011). At December 31, 2012 management estimates that these payments are expected to be made over the next 50 years with the majority of payments being made in years 2041 to 2062. The Bank of Canada's long term bond rate of 2.36 per cent (2.49 per cent at December 31, 2011) and an inflation rate of 2.0 per cent (2.0 per cent at December 31, 2011) were used to calculate the present value of the decommissioning provision.

7. Shareholders' capital

Authorized: Unlimited number of voting common shares

Issued and Outstanding

Common Shares (no par value)	Number of Common Shares	Amount $
Balance, December 31, 2010	**131,875,382**	**755,831**
Common shares issued	4,899,000	115,126
Common share issuance costs (net of tax)	-	(3,854)
Common shares issued by private placement	906,196	17,150
Common shares issued pursuant to DRIP	113,527	1,973
Common shares issued pursuant to OTUPP	166,196	2,889
Balance, December 31, 2011	**137,960,301**	**889,115**
Common shares issued	4,628,750	115,024
Common shares issued for acquisition	5,404,007	112,187
Common share issuance costs (net of tax)	-	(3,896)
Common shares issued by private placement	525,655	11,952
Balance, December 31, 2012	**148,518,713**	**1,124,382**

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible unitholders could elect to reinvest their monthly cash distributions in additional trust units at a 5 percent discount to market price. The DRIP plan incorporated an Optional Trust Unit Purchase Plan ("OTUPP") which provided unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP. The DRIP and the OTUPP plans were cancelled December 31, 2010 with the final shares issued under the plan January 14, 2011.

On December 31, 2010, Peyto completed a private placement of 655,581 common shares to employees and consultants for net proceeds of $12.4 million ($18.95 per share). These common shares were issued on January 6, 2011.

On January 14, 2011, 279,723 common shares (113,527 pursuant to the DRIP and 166,196 pursuant to the OTUPP) were issued for net proceeds of $4.9 million.

On March 25, 2011, Peyto completed a private placement of 250,615 common shares to employees and consultants for net proceeds of $4.7 million ($18.86 per share).

On December 16, 2011, Peyto closed an offering of 4,899,000 common shares at a price of $23.50 per common share, receiving proceeds of $110.1 million (net of issuance costs).

On December 31, 2011 Peyto completed a private placement of 397,235 common shares to employees and consultants for net proceeds of $9.7 million ($24.52 per share). These common shares were issued on January 13, 2012.

On March 23, 2012 Peyto completed a private placement of 128,420 common shares to employees and consultants for net proceeds of $2.2 million ($17.22 per share).

On August 14, 2012 Peyto issued 5,404,007 common shares which were valued at $112.2 million (net of issuance costs) ($20.76 per share) in relation to the closing of a corporate acquisition (Note 3).

On December 11, 2012, Peyto closed an offering of 4,628,750 common shares at a price of $24.85 per common share, receiving proceeds of $110.0 million (net of issuance costs).

Shares to be issued

On December 31, 2012 the Company completed a private placement of 154,550 common shares to employees and consultants for net proceeds of $3.5 million ($22.38 per share). These common shares were issued on January 7, 2013.

Per share amounts
Earnings per share or unit have been calculated based upon the weighted average number of common shares outstanding for the year ended December 31, 2012 of 141,093,829 (2011 – 133,196,103). There are no dilutive instruments outstanding.

Dividends
During the year ended December 31, 2012, Peyto declared and paid dividends of $0.72 per common share or $0.06 per common share per month, totaling $101.6 million (2011 - $0.72 or $0.06 per share per month, $96.1 million).

On January 15, 2013 Peyto declared dividends of $.06 per common share paid on February 15, 2013. On February 15, 2013, Peyto declared dividends of $0.06 per common share to be paid to shareholders of records February 28, 2013. These dividends will be paid March 15, 2013.

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

Accumulated hedging gains
Gains and losses from cash flow hedges are accumulated until settled. These outstanding hedging contracts are recognized in earnings on settlement with gains and losses being recognized as a component of net revenue. Further information on these contracts is set out in Note 13.

8. Operating expenses

The Company's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering recoveries related to jointly controlled assets and third party natural gas reduce operating expenses.

	Years ended December 31	
	2012	**2011**
Field expenses	46,591	38,240
Processing and gathering recoveries	(15,331)	(10,861)
Total operating expenses	**31,260**	**27,379**

9. General and administrative expenses

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

	Years ended December 31	
	2012	**2011**
General and administrative expenses	12,822	11,402
Overhead recoveries	(8,976)	(6,491)
Net general and administrative expenses	**3,846**	**4,911**

10. Finance costs

	Years ended December 31	
	2012	**2011**
Interest expense	25,401	21,881
Accretion of discount on provisions	1,044	840
	26,445	**22,721**

11. Future performance based compensation

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

Reserve based component
The reserves value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity, dividends, general and administrative costs and interest, of proved producing reserves calculated using a

constant price at December 31 of the current year and a discount rate of 8%.

Market based component
Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 6% of the total number of common shares 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 dividends of a common share for that period. The 2012 market based component was based on i) 0.5 million vested rights at an average grant price of $13.50, average cumulative distributions of $1.44 and a ten day weighted average closing price of $18.83, ii) 0.6 million vested rights at an average grant price of $19.13, average cumulative distributions of $0.72 and a ten day weighted average price of $24.75 and iii) 0.07 million vested rights at an average grant price of $20.63, average cumulative dividends of $0.48 and a ten day weighted average price of $22.58.

The total amount expensed under these plans was as follows:

($000)	**2012**	2011
Market based compensation	7,762	17,486
Reserve based compensation	4,825	5,210
Total market and reserves based compensation	**12,587**	**22,696**

For the future market based component, compensation costs as at December 31, 2012 were a recovery of $2.8 million related to 0.6 million non-vested rights with an average grant price of $19.13, average cumulative dividends of $0.72 and 0.1 million non-vested rights with an average grant price of $20.63 and average cumulative dividends of $0.48. (2011 – 0.6 million non-vested rights with an average grant price of $13.50 and 1.3 million non-vested rights with an average grant price of $19.13 were $1.2 million). The cumulative provision for future performance based compensation as at December 31, 2012 was $2.7 million (2011 - $5.6 million).

The fair values were calculated using a Black-Scholes valuation model. The principal inputs to the option valuation model were:

	December 31 2012	**December 31 2011**
Share price	$22.58	$24.75
Exercise price	$18.41 - $19.91	$12.06 - $18.41
Expected volatility	0%	0%
Option life	1 - 2 years	1 - 2 years
Dividend yield	0%	0%
Risk-free interest rate	1.08%	0.97%

Subsequent to December 31, 2012, 3.0 million rights were granted at a price of $22.58 to be valued at the ten day weighted average market price at December 31, 2013 and vesting one third on each of December 31, 2013, December 31, 2014 and December 31, 2015.

12. Income taxes

($000)	**2012**	**2011**
Earnings before income taxes	130,093	168,145
Statutory income tax rate	25.00%	26.50%
Expected income taxes	32,523	44,558
Increase (decrease) in income taxes from:		
Corporate income tax rate change	-	(2,429)
True-up tax pools	1,634	(7,706)
Resolution of reassessment and other	1,985	5,539
Total income tax expense (recovery)	**36,142**	39,962

Deferred income tax expense (recovery)	34,274	35,013
Current tax expense	1,868	4,949
Total income tax expense (recovery)	**36,142**	39,962

Differences between tax base and reported amounts for depreciable assets	207,805	167,282
Derivative financial instruments	1,930	11,208
Share issuance costs	(3,095)	(3,083)
Future performance based bonuses	(684)	(1,389)
Provision for decommission provision	(14,550)	(9,509)
Cumulative eligible capital	(6,599)	(7,096)
Attributable crown royalty income carryforward	-	(4,964)
Tax loss carry-forwards recognized	(10,566)	(259)
Deferred income taxes	**174,241**	152,190

At December 31, 2012 the Company has tax pools of approximately $1,288.0 million (2011 - $998.1 million) available for deduction against future income. The Company has approximately $42.1 million in loss carry-forwards (2011 - $0.4 million) available to reduce future taxable income.

Canada Revenue Agency ("CRA") conducted an audit of restructuring costs incurred in the 2003 trust conversion. On September 25, 2008, the CRA reassessed on the basis that $41 million of these costs were not deductible and treated them as an eligible capital amount. The Company filed a notice of objection and the CRA confirmed the reassessment. Examinations for discovery have been completed. The Tax Court of Canada had agreed to both parties' request to hold the Company's appeal in abeyance pending a decision of the Supreme Court of Canada to hear another taxpayer's appeal. The other appeal raised issues that are similar in principle to those raised in the Company's appeal. As the other taxpayer's appeal was unsuccessful with the Federal Court of Appeal, in 2011, the Company expensed the income tax of $4.9 million and interest charges of $2.2 million assessed and paid in 2008. Subsequently, the Alberta Government reassessed the same time period resulting in income taxes payable of $1.8 million and interest charges of $1.4 million paid in 2013.

13. Financial instruments

Financial instrument classification and measurement

Financial instruments of the Company carried on the consolidated balance sheet are carried at amortized cost with the exception of cash and financial derivative instruments, specifically fixed price contracts, which are carried at fair value. There are no significant differences between the carrying amount of financial instruments and their estimated fair values as at December 31, 2012.

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

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

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

Fair values of financial assets and liabilities

The Company's financial instruments include cash, accounts receivable, financial derivative instruments, due from private placement, current liabilities, provision for future performance based compensation and long term debt. At December 31, 2012 and 2011, cash and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities and provision for future performance based compensation approximate their fair value due to their short term nature. The carrying value of the long term debt approximates its fair value due to the floating rate of interest charged under the credit facility.

Market risk

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

Commodity price risk management

The Company is a party to certain derivative financial instruments, including fixed price contracts. The Company 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 Company 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 Company's firm commitment or forecasted transactions and the underlying basis of the instruments correlate highly with the Company's exposure.

Following is a summary of all risk management contracts in place as at December 31, 2012:

Propane **Period Hedged**	**Type**	**Monthly Volume**	**Price** **(USD)**
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$49.56/bbl
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$44.10/ bbl
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$32.34/ bbl
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$33.60/ bbl
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$32.97/ bbl
October 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$34.01/ bbl
October 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$34.65/ bbl
October 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$36.96/ bbl
January 1, 2013 to March 31, 2013	Fixed Price	4,000 bbl	$36.12/bbl
April 1, 2013 to June 30, 2013	Fixed Price	4,000 bbl	$34.86/bbl
April 1, 2013 to December 31, 2013	Fixed Price	4,000 bbl	$30.66/bbl
April 1, 2013 to December 31, 2013	Fixed Price	4,000 bbl	$32.34/bbl
April 1, 2013 to December 31, 2013	Fixed Price	4,000 bbl	$34.86/bbl
April 1, 2013 to December 31, 2013	Fixed Price	4,000 bbl	$35.39/bbl

Butane **Period Hedged**	**Type**	**Monthly Volume**	**Price** **(USD)**
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$80.64/bbl
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$58.38/bbl
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$60.06/bbl
September 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$60.06/bbl
October 1, 2012 to March 31, 2013	Fixed Price	2,000 bbl	$66.36/bbl

Iso-Butane **Period Hedged**	**Type**	**Monthly Volume**	**Price** **(USD)**
September 1, 2012 to March 31, 2013	Fixed Price	1,000 bbl	$82.32/bbl
September 1, 2012 to March 31, 2013	Fixed Price	1,000 bbl	$60.48/bbl
September 1, 2012 to March 31, 2013	Fixed Price	1,000 bbl	$62.58/bbl
September 1, 2012 to March 31, 2013	Fixed Price	1,000 bbl	$62.58/bbl
October 1, 2012 to March 31, 2013	Fixed Price	1,000 bbl	$69.30/bbl

Natural Gas **Period Hedged**	**Type**	**Daily Volume**	**Price** **(CAD)**
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.055/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.17/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
November 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ
April 1, 2012 to March 31, 2013	Fixed Price	5,000 GJ	$2.20/GJ

April 1, 2012 to March 31, 2013	Fixed Price	5,000 GJ	$2.31/GJ
April 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$2.52/GJ
April 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$3.00/GJ
May 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$2.30/GJ
August 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$3.00/GJ
August 1, 2012 to October 31, 2014	Fixed Price	5,000 GJ	$3.10/GJ
November 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$2.60/GJ
November 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$3.005/GJ
November 1, 2012 to October 31, 2013	Fixed Price	5,000 GJ	$3.00/GJ
November 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$2.81/GJ
November 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$3.00/GJ
November 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$3.05/GJ
November 1, 2012 to March 31, 2014	Fixed Price	5,000 GJ	$3.02/GJ
November 1, 2012 to October 31, 2014	Fixed Price	5,000 GJ	$3.0575/GJ
January 1, 2013 to October 31, 2013	Fixed Price	5,000 GJ	$3.42/GJ
January 1, 2013 to December 31, 2013	Fixed Price	5,000 GJ	$3.105/GJ
January 1, 2013 to March 31, 2013	Fixed Price	5,000 GJ	$3.32/GJ
January 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.00/GJ
January 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.02/GJ
April 1, 2013 to October 31, 2013	Fixed Price	5,000 GJ	$3.205/GJ
April 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.105/GJ
April 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.53/GJ
April 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.45/GJ
April 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.50/GJ
April 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.08/GJ
April 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.17GJ
November 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.50/GJ

As at December 31, 2012, Peyto had committed to the future sale of 261,000 barrels of natural gas liquids at an average price of $39.86 USD per barrel and 59,810,000 gigajoules (GJ) of natural gas at an average price of $3.19 per GJ or $3.74 per mcf. Had these contracts been closed on December 31, 2012, Peyto would have realized a gain in the amount of $7.7 million. If the AECO gas price on December 31, 2012 were to increase by $1/GJ, the unrealized gain would decrease by approximately $59.8 million. An opposite change in commodity prices rates would result in an opposite impact on other comprehensive income.

Subsequent to December 31, 2012 Peyto entered into the following contracts:

Propane **Period Hedged**	**Type**	**Monthly Volume**	**Price** **(USD)**
April 1, 2013 to December 31, 2013	Fixed Price	4,000 bbl	$34.44/bbl

Natural Gas **Period Hedged**	**Type**	**Daily Volume**	**Price** **(CAD)**
April 1, 2013 to March 31, 2014	Fixed Price	5,000 GJ	$3.10/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.25/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.30/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.33/GJ
April 1, 2013 to October 31, 2014	Fixed Price	7,500 GJ	$3.20/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.22/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.20/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.1925/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.25/GJ
April 1, 2013 to October 31, 2014	Fixed Price	5,000 GJ	$3.30/GJ
November 1, 2013 to March 31, 2015	Fixed Price	5,000 GJ	$3.6025/GJ

Interest rate risk
The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Company 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 Company's earnings before income tax for the year ended December 31, 2012 would decrease by $4.2 million. An opposite change in interest rates will result in an opposite impact on earnings before income tax.

Credit risk
A substantial portion of the Company'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 Company generally extends unsecured credit to purchasers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company'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 Company has not previously experienced any material credit losses on the collection of accounts receivable. Of the Company's revenue for the year ended December 31, 2012, approximately 13% was received from one company (December 31, 2011 – 54%, four companies (18%, 13%, 12% and 11%)). Of the Company's accounts receivable at December 31, 2012, approximately 14% was receivable from a single company (December 31, 2011 – 15%, one company). The maximum exposure to credit risk is represented by the carrying amount on the balance sheet. There are no material financial assets that the Company considers past due and no accounts have been written off.

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

Counterparties to financial instruments expose the Company 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 Company assesses quarterly if there should be any impairment of financial assets. At December 31, 2012, there was no impairment of any of the financial assets of the Company.

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

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

The Company'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 Company to conduct equity issues or obtain debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to certain losses.

The following are the contractual maturities of financial liabilities as at December 31, 2012:

	< 1 Year	**1-2 Years**	**2-5 Years**	**Thereafter**
Accounts payable and accrued liabilities	164,946			
Dividends payable	8,911			
Provision for future market and reserves based bonus	2,677	59		
Current taxes payable	1,890			
Long-term debt[(1)]		430,000		
Senior secured notes				150,000

(1) Revolving credit facility renewed annually (*see Note 5*)

14. Capital disclosures

The Company'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 Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its underlying assets. The Company considers its capital structure to include Shareholders' equity, debt and working capital. To maintain or adjust the capital structure, the Company may from time to time, issue common shares, raise debt, adjust its capital spending or change dividends paid to manage its current and projected debt levels. The Company monitors capital based on the following 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 Company 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.

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

	December 31 2012	December 31 2011
Shareholders' equity	1,210,067	1,015,708
Long-term debt	580,000	470,000
Working capital (surplus) deficit	74,884	(40,232)
	1,864,951	**1,445,476**

15. Related party transactions

An officer and director of the Company is a partner of a law firm that provides legal services to the Company. For the year ended December 31, 2012, legal fees totaled $1.2 million (2011 - $0.8 million). As at December 31, 2012, an amount due to this firm of $1.2 million was included in accounts payable (2011 - $0.7 million).

The Company has determined that the key management personnel consists of it key employees, officers and directors. In addition to the salaries and directors fees paid to these individuals, the Company also provides compensation in the form of market and reserve based bonus to some of these individuals. Compensation expense of $1.3 million is included in general and administrative expenses and $5.0 million in market and reserves based bonus relating to key management personnel for the year 2012 (2011 - $1.7 million in general and administrative and $10.1 million in market and reserves based bonus).

16. Commitments

Peyto has contractual obligations and commitments as follows:

	2013	2014	2015	2016	2017	Thereafter
Note repayment(1)	-	-	-	-	-	150,000
Interest payments(2)	4,635	6,830	6,830	6,830	6,830	18,785
Transportation commitments	14,033	13,077	9,749	4,575	1,221	924
Operating leases	1,678	1,694	522	-	-	-
Total	20,346	21,601	17,101	11,405	8,051	169,709

(1) Long-term debt repayment on senior secured notes

(2) Fixed interest payments on senior secured notes

Officers

Darren Gee
President and Chief Executive Officer

Scott Robinson
Executive Vice President and Chief Operating Officer

Kathy Turgeon
Vice President, Finance and Chief Financial Officer

Stephen Chetner
Corporate Secretary

Tim Louie
Vice President, Land

David Thomas
Vice President, Exploration

Jean-Paul Lachance
Vice President, Exploitation

Directors

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

Auditors

Deloitte LLP

Solicitors

Burnet, Duckworth & Palmer LLP

Bankers

Bank of Montreal
Union Bank, Canada Branch
Royal Bank of Canada
Canadian Imperial Bank of Commerce
HSBC Bank Canada
The Toronto-Dominion Bank
Alberta Treasury Branches
Canadian Western Bank

Transfer Agent

Valiant Trust Company

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