TSX:PPY

PAINTED PONY PETROLEUM LTD.

DRIVING FORWARD

2014 ANNUAL REPORT TO SHAREHOLDERS

PAINTED PONY PETROLEUM LTD.

2014 ANNUAL REPORT TO SHAREHOLDERS

CORPORATE PROFILE

Painted Pony is a publicly-traded natural gas corporation based in Western Canada. The Corporation is primarily focused on the development of natural gas and natural gas liquids from the Montney formation in northeast British Columbia. Painted Pony's common shares trade on the Toronto Stock Exchange under the symbol "PPY".

ANNUAL GENERAL MEETING

Painted Pony Petroleum Ltd. invites shareholders and interested parties to attend its Annual General Meeting to be held in the Bennett Room at the Ranchmen's Club, 710 – 13th Avenue SW, Calgary, Alberta, at 3:00 pm (Calgary time), on May 14, 2015. Shareholders not attending are encouraged to complete the form of proxy and deliver it in accordance with the instructions therein at their earliest convenience.

TABLE OF CONTENTS

Cover painting "Painted Pony Express", 48"X72", oil on canvas by Paul Van Ginkel (www.paulvanginkel.com).

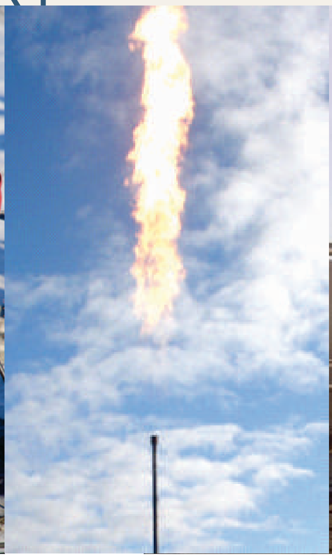
HIGHLIGHTS

	Year ended December 31, 2014	2013	Change
Financial			
($ millions, except per share and shares outstanding)			
Petroleum and natural gas revenue[1]	**160.5**	103.1	56%
Funds flow from operations[2]	**88.9**	51.2	74%
Per share - basic[3] and diluted[4]	**0.97**	0.58	67%
Net loss	**(15.6)**	(5.7)	174%
Per share - basic[3] and diluted[4]	**(0.17)**	(0.06)	183%
Capital expenditures	**270.5**	146.6	85%
Working capital (deficiency)[5]	**2.8**	(16.3)	117%
Total assets	**737.8**	635.1	16%
Shares outstanding *(000s)*	**99,470**	88,457	12%
Basic weighted-average shares *(000s)*	**91,245**	88,420	3%
Fully diluted weighted-average shares *(000s)*	**92,068**	88,488	4%
Operational			
Daily production volumes			
Natural gas *(mcf/d)*	**70,593**	42,853	65%
Natural gas liquids *(bbls/d)*	**923**	449	106%
Crude oil *(bbls/d)*	**503**	1,102	(54%)
Total *(boe/d)*	**13,192**	8,693	52%
Total *(mcfe/d)*	**79,152**	52,158	52%
Realized prices			
Natural gas *($/mcf)*	**4.48**	3.45	30%
Natural gas liquids *($/bbl)*	**75.39**	62.54	21%
Crude oil *($/bbl)*	**102.34**	93.02	10%
Total *($/boe)*	**33.34**	32.49	3%
Total *($/mcfe)*	**5.56**	5.42	3%
Field operating netbacks[6]			
British Columbia *($/boe)*	**19.99**	13.96	43%
Saskatchewan *($/boe)*[7]	**52.36**	48.72	7%
Total *($/boe)*	**21.34**	18.88	13%
Total *($/mcfe)*	**3.56**	3.15	13%

1. Before royalties.
2. Funds flow from operations and funds flow from operations per share (basic and diluted) are non-GAAP measures used to represent cash flow from operating activities before the effects of changes in non-cash working capital and decommissioning expenditures. Funds flow from operations per share is calculated by dividing funds flow from operations by the weighted average number of basic or diluted shares outstanding in the period.
3. Basic per share information is calculated on the basis of the weighted average number of shares outstanding in the period.
4. Diluted per share information reflects the potential dilutive effect of options.
5. Working capital (deficiency) is a non-GAAP measure calculated as current assets less current liabilities.
6. Field operating netbacks is a non-GAAP measure calculated on a per unit basis as natural gas, crude oil and natural gas liquids revenues less royalties, operating and transportation costs.
7. The Saskatchewan crude oil properties were disposed of on July 30, 2014.

CORPORATE HISTORY






2007

Closed the Corporation's initial public offering for gross proceeds of $12 million.

2008

Acquired producing natural gas properties and undeveloped land in northeast BC for $21.2 million, setting the stage for Painted Pony's growth in the Montney.

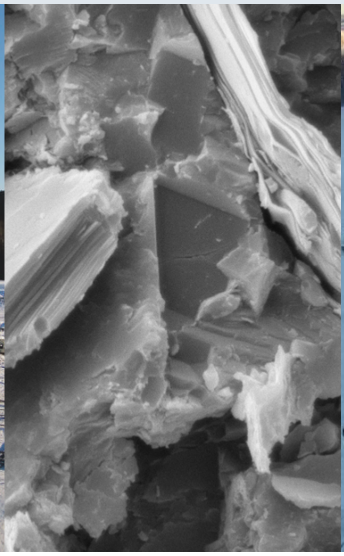
2009

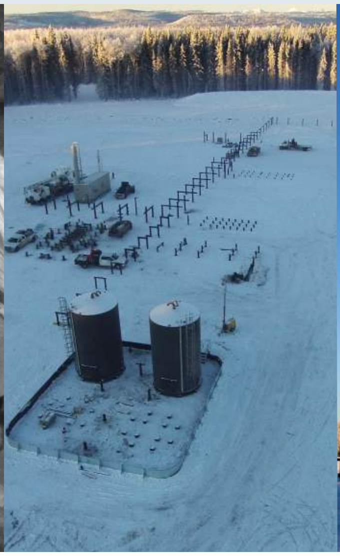
Drilled first vertical Montney well on Cameron property at a-10-J/94-B-09.

2010

Drilled the Corporation's first operated horizontal Montney well at the Blair property.

Drilled the first middle Montney well in the region and consequently announce a major Montney discovery.





2011

Drilled and completed the Corporation's first 3 well pad at Blair, targeting the upper, middle and lower Montney zones.

Drilled and completed d-44-C/94-B-16 lower Montney well that tested at 24.5 mmcf/d.

2012

Acquired the Townsend property for $108 million, setting the stage for liquids rich Montney growth.

2013

Painted Pony graduated to and commenced trading on the Toronto Stock Exchange under the symbol PPY.

Painted Pony implements technological advancements utilizing open-hole ball-drop completions on its Montney horizontal wells.

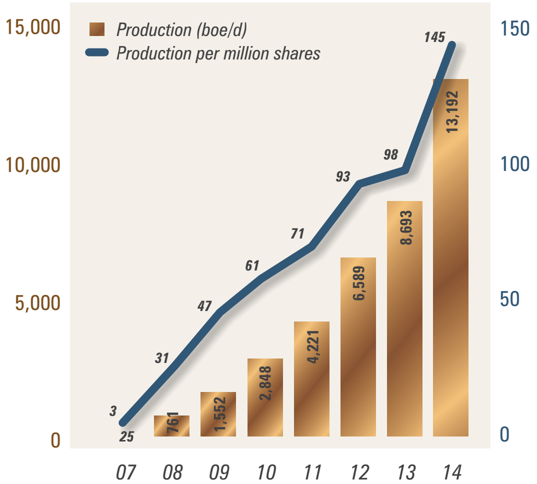
2014

Entered into a strategic alliance with AltaGas Ltd. for the development of essential liquids-rich gas processing infrastructure in northeast British Columbia.

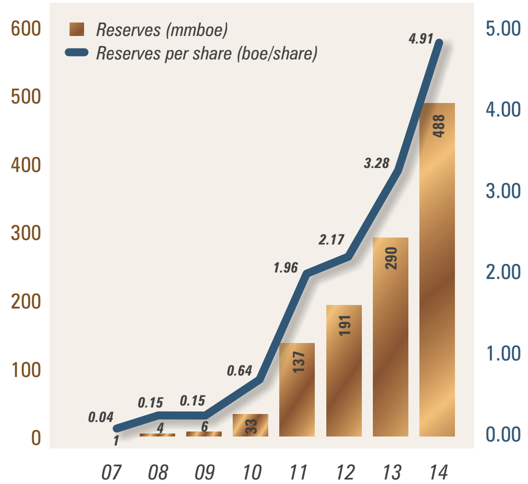
Sold the Saskatchewan properties for $100 million, allowing the Corporation to focus entirely on its growing Montney project.

Grew proved plus probable reserves to 2.9 tcfe (488 mmboe).

PRODUCTION



RESERVES



TO OUR SHAREHOLDERS

It is with great pleasure and pride that we provide financial and operating results of Painted Pony for 2014, which saw the Corporation take several significant steps towards delivering on the tremendous growth potential of one of the finest natural gas assets in North America.

Productivity Gains Continue to Deliver Low Cost Supply

After being the first to implement the open-hole ball-drop completion technique in the Montney in our area during 2013, Painted Pony completed all wells in 2014 using this technique and continues to see cost savings in excess of $750,000 per well, with production increases of over 30% compared to previously used methods. In keeping with the Corporation's philosophy of methodically evaluating and implementing new technologies and techniques to continually improve our top tier cost structure, 2014 saw Painted Pony begin drilling wells using a parallel-pair spacing pattern. Production improvements have exceeded expectations at no incremental cost and all wells expected to be drilled in 2015 will utilize this approach. The Corporation recently completed its first parallel-triple and is also evaluating the benefits of increasing the number of stages per well and increasing the amount of proppant used.

These drilling and completion improvements, combined with very high quality geology, have resulted in Painted Pony wells having the highest average peak rates of any Montney operator over the past two years and drove production growth of 52% in 2014 to 13,192 boe/d. These continued improvements also led to positive technical revisions of 501 Bcfe to proved plus probable (“2P”) reserve in 2014, with undeveloped reserves per well increasing 30%. These productivity enhancements are expected to continue driving lower supply costs as undeveloped 2P reserves increased 68% during 2014, while future development capital (“FDC”) only increased 29%, resulting in a 23% reduction to FDC per Mcfe.

GLJ estimated that Painted Pony increased its total 2P reserves by 68% to 2.9 Tcfe (488 MMboe) during 2014, weighted 90% towards natural gas, with an associated 75% increase in NPV10 to $2.6 billion. This was achieved at a finding, development and acquisition (“FD&A”) cost of $0.70/Mcfe that resulted in an industry leading recycle ratio of 5.1 times and replaced 2014 production by 4,215%.

Top Tier Growth with a Strong Balance Sheet

Entering 2015 with no net-debt leaves Painted Pony very well positioned to preserve a strong balance sheet during this period of weak commodity prices, taking advantage of continued improvements in well productivity and lower service costs, while positioning the Corporation for significant growth upon completion of the AltaGas Townsend Facility in 2016. Painted Pony's board of directors has approved a prudent capital expenditure budget of $104 million for 2015 that is expected to deliver production growth of 21% to 16,000 boe/d from only 6 (6.0) net wells. The remaining 8 (8.0) net wells planned for 2015 are pre-drills to be completed and tied into the AltaGas Townsend facility in 2016.

Longer term optionality comes from the Corporation's properties being ideally situated to supply future LNG export projects on the west coast. This is due to a combination of a huge concentrated resource consisting of the highest productivity Montney wells, with favourable royalty credits from being west of the B.C. Royalty line, high heat content gas, as well as proximity to infrastructure and takeaway capacity. Given the strong relationship with our Strategic Alliance partner, Painted Pony is optimistic about supplying natural gas to a targeted AltaGas LNG project in what could be the first LNG export facility off the British Columbia coast.

"Life will change without our permission. It's our attitude that will determine the ride."
~Author Unknown

Strategic Alliance with AltaGas Enables Visible, Profitable Growth

Painted Pony entered into a 15-year strategic alliance with AltaGas Ltd. in August for the development of processing infrastructure and marketing services for natural gas and natural gas liquids. The Strategic Alliance will provide for the development of essential liquids-rich gas processing infrastructure in northeast British Columbia and may provide preferred access to international energy markets for Painted Pony's Montney production. In the first phase of the Strategic Alliance, AltaGas will construct and operate a 198 MMcf/d shallow-cut gas processing facility in the Montney resource play, of which Painted Pony will maintain the right to 150 MMcf/d of firm capacity upon completion in mid-2016 and to the full 198 MMcf/d beginning in the second year of operation. The Strategic Alliance brings viable solutions for providing long-term marketing optionality for Painted Pony's rapidly growing natural gas and natural gas liquids production. In addition, it allows the Corporation to focus its capital allocation on higher return drilling and completion activities.

Montney Land Purchase Expands Liquids Rich Drilling Inventory

At a British Colombia Crown land sale in November, Painted Pony acquired 14.5 sections of prospective Montney land for $66.8 million, immediately adjacent to the Corporation's liquids-rich Montney natural gas project in the Townsend area. This 50% increase in Painted Pony's Townsend land base was a strategic acquisition, given limited opportunities to acquire Crown land in the area. The Townsend area is a "sweet spot" of the northeast BC Montney where the average reservoir thickness is approximately 340 metres (1,100 feet) and liquids yields are substantially higher than regional averages. The acquired land is expected to add over 170 liquids-rich drilling locations within three prospective intervals of the Montney and is in close proximity to the AltaGas Ltd. Townsend gas processing facility. The new acreage is believed to exhibit the same over-pressured geological characteristics as the Corporation's existing Townsend block, with wells expected to yield similar liquids recovery of 40 to 80 bbls/MMcf of condensate, propane and butane (C3+).

Saskatchewan Disposition Enabled Accelerated Montney Growth with Pristine Balance Sheet

The timing of the sale of the Corporation's Saskatchewan properties for $100 million in July was chosen to capture a window of strong global oil markets with prices in the US$100/bbl range, combined with an active and robust environment for oil-weighted transactions in western Canada. Continued improvement in Montney well productivity meant no change in full year production guidance, despite the sale of 980 boe/d. Proceeds allowed the Corporation to repay all bank debt, while also redeploying capital and allocating all resources towards its high return Montney initiatives.

The commitment of our Directors, Officers and staff has been key to the success of Painted Pony in the past and will continue to be in the future. I truly thank them for their efforts and I look forward to their continued contributions in 2015 and beyond. I would also like to thank our suppliers, the Government agencies and First Nations groups for their continued support of our operations.

Painted Pony's focus over the past year has been on positioning the Corporation to become a leading British Columbia Montney natural gas producer, while enhancing the value inherent in the Corporation's assets for you, our shareholders. As I look back on our performance in 2014, it is evident that we have executed on and surpassed our goals. Painted Pony delivered exceptional results in all aspects of its operations including cash flow, production and reserves growth. Our goal for 2015 is to continue to provide impressive growth to our shareholders through our well established fundamental operating principles.

Patrick R. Ward
President and Chief Executive Officer
March 4, 2015

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Painted Pony Petroleum Ltd. ("Painted Pony" or the "Corporation") should be read in conjunction with the consolidated financial statements and related notes thereto for the years ended December 31, 2014 and December 31, 2013. This commentary is dated March 4, 2015.

The annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The financial data presented is in accordance with IFRS in Canadian dollars, except where indicated otherwise. These documents and additional information about Painted Pony, including the Annual Information Form ("AIF") for the year ended December 31, 2013, are available on SEDAR at www.sedar.com and on the Corporation's website at www.paintedpony.ca.

Description of Corporation

Painted Pony is a natural gas corporation based in Western Canada. The Corporation is primarily focused on natural gas and natural gas liquids from the Montney formation in northeast British Columbia. The common shares of Painted Pony ("Common Shares") trade on the Toronto Stock Exchange ("TSX") under the symbol "PPY". The Corporation's head office is located at Suite 1800, 736 – 6th Avenue SW, Calgary, Alberta.

Painted Pony commenced commercial operations on April 3, 2007 upon completion of a financial reorganization as part of an overall restructuring of the Corporation. On May 23, 2007, subsequent to completion of an initial public offering on May 17, 2007, the Class A shares and Class B shares of Painted Pony began trading on the TSX Venture Exchange. Painted Pony then commenced an active exploration program. Effective December 1, 2011, the Class B shares of Painted Pony were converted to Class A shares and, as such, the Class B shares were de-listed from the TSX Venture Exchange. Effective June 7, 2012, the Class A shares of Painted Pony were re-designated as Common Shares. Effective October 17, 2013, the Common Shares of Painted Pony began trading on the TSX under the symbol "PPY" and were de-listed from the TSX Venture Exchange.

Non-GAAP Measures

This MD&A contains the term "funds flow from operations", which should not be considered an alternative to, or more meaningful than, cash flows from operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. Funds flow from operations and funds flow from operations per share (basic and diluted) do not have any standardized meanings prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and considers funds flow from operations to be a key measure as it demonstrates the Corporation's ability to generate the cash necessary to fund future capital investment and to repay debt. Funds flow from operations per share is calculated using the basic and diluted weighted average number of shares for the period. The Corporation reconciles funds flow from operations to cash flows from operating activities, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

Funds Flow from Operations

	Three months ended December 31,		Year ended December 31,	
($000s)	**2014**	**2013**	**2014**	**2013**
Cash flows from operating activities	**15,977**	10,229	**90,303**	49,113
Changes in non-cash working capital	**(3,795)**	1,865	**(2,174)**	1,731
Decommissioning expenditures	**401**	228	**798**	383
Funds flow from operations	**12,583**	12,322	**88,927**	51,227

MANAGEMENT'S DISCUSSION AND ANALYSIS

This MD&A also contains other industry benchmarks and terms, such as "working capital (deficiency)", calculated as current assets less current liabilities, and "field operating netbacks", calculated on a per unit basis as natural gas, natural gas liquids ("NGLs") and crude oil revenues, less royalties and operating and transportation costs. These are not recognized measures under IFRS. Management believes these measures are useful supplemental measures of the net position of current assets and current liabilities of the Corporation and the profitability relative to commodity prices, respectively. Readers are cautioned, however, that these measures should not be construed as alternatives to other terms such as current and long-term debt or comprehensive income determined in accordance with IFRS as measures of performance. Painted Pony's method of calculating these measures may differ from other companies and, accordingly, may not be comparable to similar measures used by other companies.

Results of Operations – Overview

Results of operations for 2014 represent significant steps towards the advancement of Painted Pony's focused five year plan. During the year the Corporation entered into a 15-year strategic alliance with AltaGas Ltd. ("AltaGas") for the development of processing infrastructure and marketing services for natural gas and natural gas liquids (the "Strategic Alliance"). The Strategic Alliance will provide for the development of essential liquids-rich processing infrastructure in northeast British Columbia and may provide preferred access to international energy markets for Painted Pony's Montney production.

As part of the Strategic Alliance, AltaGas has begun field lease work, and application and construction preparation on a 198 MMcf/d gas processing facility at the Corporation's Townsend property, of which Painted Pony will maintain the right to a minimum of 150 MMcf/d of firm capacity in its first year. In early 2015, Painted Pony and AltaGas agreed that during the second year of commercial operations, Painted Pony's capacity in the facility will increase to the full 198 MMcf/d. Based upon current circumstances, Painted Pony expects that the facility will be treated as a finance lease upon commencement of commercial operations. During the 15-year term of the lease, Painted Pony will have a take or pay obligation on a component of its firm capacity. Painted Pony and AltaGas have revised the construction schedule for the expected completion of the AltaGas Townsend Facility to the third quarter of 2016, which provides flexibility to Painted Pony's drilling and completion plans in 2015 and 2016. Concurrent with the Strategic Alliance, Painted Pony completed a private placement with AltaGas for 4,166,666 Common Shares at $12.00 per share, for total proceeds of approximately $50 million.

During the year the Corporation also completed the disposition of its southeast Saskatchewan crude oil assets for cash consideration of approximately $100 million. The disposition was completed with a view to positioning the Corporation as a highly focused Montney natural gas and natural gas liquids producer.

In the fourth quarter, Painted Pony completed a crown land acquisition for 14.5 net sections of 100% working interest prospective Montney land for $66.8 million. The land is directly adjacent to Painted Pony's liquids-rich Townsend area in northeast British Columbia. Following its successful land acquisition, on December 2, 2014 the Corporation completed a bought deal financing of 5,275,050 Common Shares at $12.00 per share for total gross proceeds of $63.3 million. On December 8, 2014 the Corporation increased its syndicated credit facilities from $150 million to $175 million, which remained undrawn as at December 31, 2014.

During the year the Corporation drilled 21 (19.5 net) Montney natural gas wells, all of which utilized the industry leading open-hole ball drop completion system. Painted Pony continues to see significant improvements in per well production rates as a result of new technology, including open-hole ball drop completions, parallel pair drilling and shorter stage length fracturing. These technological advancements all contributed to a 65% increase in natural gas production volumes to an annual average 70,593 Mcfe/d for the year ended December 31, 2014. Facilities capital during the year was spent on the construction of a 25 MMcf/d natural gas compression and dehydration facility at West Blair and on a 25 MMcf/d expansion of the processing capacity at its 50% working interest Daiber dry gas facility, both of which have provided for incremental production volumes coming on stream in the first quarter of 2015.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Outlook

As a result of the current commodity price environment, Painted Pony has reduced its 2015 capital program to $104 million. In 2015 the Corporation intends to drill 14 Montney horizontal natural gas wells on its 100% working interest lands in the Blair and Townsend areas, and expects annual production volumes to average approximately 16,000 boe/d, representing an anticipated 21% increase in production volumes over the year ended December 31, 2014. This will provide the Corporation with an ability to focus resources on pre-drilling liquids rich wells for the anticipated startup of the AltaGas Townsend Facility in the third quarter of 2016. With undrawn credit facilities at December 31, 2014 the Corporation is well positioned to deliver its modified development plans while retaining a strong balance sheet.

Funds Flow from Operations and Net Loss

Painted Pony generated funds flow from operations of $12.6 million during the fourth quarter of 2014, compared to $12.3 million during the fourth quarter of 2013. Comparable funds flow from operations was a result of lower netbacks after the sale of the Corporation's crude oil assets, offset by higher natural gas and natural gas liquids production volumes. During the year ended December 31, 2014, the Corporation generated funds flow from operations of $88.9 million, compared to $51.2 million during the year ended December 31, 2013. The increase in funds flow from operations for 2014 was primarily driven by significantly higher natural gas and NGL production volumes, combined with higher natural gas prices. In the fourth quarter and year ended December 31, 2014 the Corporation also had lower per unit royalty and operating expenses but higher transportation expenses than the comparative periods.

During the fourth quarter of 2014 Painted Pony had a net loss of $3.4 million primarily due to a $9.6 million exploration and evaluation expense, compared to $4.4 million in the fourth quarter of 2013. For the year ended December 31, 2014, the net loss increased to $15.6 million as a result of a $43.4 million loss relating to the sale of the Corporation's crude oil assets during the year, compared to $5.7 million in the year ended December 31, 2013.

Average Daily Production

	Three months ended December 31,				Years ended December 31,			
	2014	% of Total	2013	% of Total	2014	% of Total	2013	% of Total
Natural gas *(mcf/d)*	**76,251**	**93**	46,841	84	**70,593**	**89**	42,853	82
NGLs *(bbls/d)*	**956**	**7**	537	6	**923**	**7**	449	5
Crude oil *(bbls/d)*	**-**	**-**	968	10	**503**	**4**	1,102	13
Total *(boe/d)*	**13,665**	**100**	9,312	100	**13,192**	**100**	8,693	100
Total *(mcfe/d)*	**81,990**	**100**	55,875	100	**79,152**	**100**	52,158	100

Fourth quarter production volumes increased 47% compared to the fourth quarter of 2013 to average 13,665 boe/d, weighted 93% towards natural gas as the Corporation disposed of its Saskatchewan crude oil assets during the third quarter of 2014. Annual average production volumes increased 52% compared to the year ended December 31, 2013. Production volume increases during the quarter and year were driven primarily by production additions from successful new drills in the Blair, Townsend and Daiber areas as well as production facility capacity additions in the Townsend area.

Painted Pony expects production volumes for both the first quarter of 2015 and the year to average 16,000 boe/d. Estimated production for the year includes the impact of an expected six week turnaround at a third party processing facility during the second and third quarters of 2015. The expected production increase is a reflection of the recent commissioning of new and expanded facilities in the Blair and Daiber areas, which have allowed shut-in production and incremental volumes from the Corporation's successful drilling program to come on stream. Expected production volumes for 2015 reflect a revision to the Corporation's previously announced drilling program given the current commodity pricing environment.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Petroleum and Natural Gas Revenue

	Three months ended December 31,		Year ended December 31,	
($000s)	**2014**	**2013**	**2014**	**2013**
Natural gas	**24,840**	16,190	**115,506**	54,029
NGLs	**5,107**	7,733	**25,393**	37,409
Crude oil	**-**	3,138	**18,797**	10,243
Other income	**56**	392	**849**	1,405
Total	**30,003**	27,453	**160,545**	103,086

Petroleum and natural gas revenue totaled $30.0 million for the three months ended December 31, 2014, representing a 9% increase over fourth quarter 2013 revenue of $27.5 million. The change in quarterly revenue is driven by a 63% increase in natural gas and a 78% increase in NGL production volumes, partially offset by lower realized commodity prices, and the sale of the Saskatchewan crude oil assets in the third quarter of 2014.

During the year ended December 31, 2014 petroleum and natural gas revenue totaled $160.5 million, compared to $103.1 million during the year ended December 31, 2013. Revenue growth for the year of 56% is consistent with the increase in production over the same period, despite the disposition of the Corporation's crude oil assets during the year.

Commodity Prices

		Three months ended December 31,		Year ended December 31,	
		2014	**2013**	**2014**	**2013**
Average benchmark prices:					
Natural Gas	- Nymex *(US$/mmbtu)*	**3.83**	3.85	**4.26**	3.73
	- AECO, daily spot *($/mcf)*	**3.60**	3.53	**4.51**	3.18
Crude Oil	- WTI *(US$/bbl)*	**73.20**	97.61	**92.91**	98.05
	- Edmonton par - light oil *($/bbl)*	**71.59**	85.70	**93.41**	91.84
Exchange rate *(US$/Cdn$)*		**0.88**	0.95	**0.91**	0.97
Realized commodity prices:					
Natural gas *($/mcf)*		**3.54**	3.76	**4.48**	3.45
NGLs *($/bbl)*		**58.05**	63.47	**75.39**	62.54
Crude oil *($/bbl)*		**-**	86.88	**102.34**	93.02
Total *($/boe)*		**23.86**	32.05	**33.34**	32.49
Total *($/mcfe)*		**3.98**	5.34	**5.56**	5.42

During the three months and year ended December 31, 2014, the Corporation realized natural gas prices that were reflective of a 2% and 1% discount to the AECO daily spot price, respectively. This compares to 7% and 8% premiums realized for the three months and year ended December 31, 2013, respectively. Painted Pony receives a price for its British Columbia natural gas that reflects a higher heat content than the benchmark, and which tends to vary from the AECO spot price with reference to the British Columbia Westcoast Station 2 reference price. During the three months and year ended this differential widened as compared to the three months and year ended December 31, 2013.

For the three months and year ended December 31, 2014, approximately 61% and 59% of the Corporation's NGL volumes were condensate, which received average prices of $71.10 per bbl and $93.80 per bbl, respectively, representing a 1% discount to the Edmonton light reference price for the quarter and approximating the reference price for the year.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Painted Pony's realized average crude oil price for the year ended December 31, 2014 was $102.34 per bbl, representing a premium of 10% over the Edmonton light reference price, compared to a premium of 1% for the year ended December 31, 2013. Painted Pony's crude oil assets were sold effective July 30, 2014.

In early 2015, the Corporation expects to receive a realized natural gas price that represents a discount to the AECO daily spot price as a result of a widening differential to Station 2, some of which will be mitigated by the commodity price risk contracts described below. Painted Pony continues to evaluate various pricing alternatives and expects to realize an average natural gas price in 2015 that is more closely aligned with the AECO daily spot price. The average prices reported by Painted Pony are reflective of month to month price and production volume changes.

Commodity Risk Management

Painted Pony has a natural gas financial risk management program that currently uses forward price swaps on a portion of its natural gas production volumes to manage some of the exposure to commodity price risk and to provide a level of stability to operating cash flows, which further enables the Corporation to fund its capital development program.

For the three months ended December 31, 2014, Painted Pony had a realized gain of $0.6 million and an unrealized gain of $5.6 million on its commodity risk management contracts. For the year ended December 31, 2014, Painted Pony had a realized loss of $3.3 million and an unrealized gain of $5.1 million on its commodity risk management contracts. For the three months and year ended December 31, 2013 the Corporation had an unrealized gain on its commodity risk management contracts of less than $0.1 million.

The Corporation's method of determination of the fair values of derivative financial instruments is disclosed in note 14 of the annual audited financial statements for the years ended December 31, 2014 and 2013.

At December 31, 2014, the Corporation held commodity price contracts summarized as follows:

Natural Gas Financial Contracts

Reference	Volume *(mcf/d)*	Term	Weighted Average Price *($/mcf)*	Options Traded	Fair Value *(000s)*
CDN$ AECO	4,739	April 2014 - March 2015	4.06	Swap	503
CDN$ AECO	33,175	January - March 2015	4.42	Swap	4,627
Total fair value					$ 5,130

Subsequent to December 31, 2014, the Corporation re-priced certain commodity price contracts for the remainder of their term, and entered into additional commodity risk management contracts. At March 4, 2015 the Corporation held commodity price contracts summarized as follows:

Natural Gas Financial Contracts

Reference	Volume *(mcf/d)*	Term	Weighted Average Price *($/mcf)*	Options Traded
CDN$ AECO	37,914	February - March 2015	3.18	Swap
CDN$ AECO	18,957	April - December 2015	3.24	Swap
CDN$ AECO	18,957	April 2015 - March 2017	3.05	Swap

Royalties

	Three months ended December 31,		Year ended December 31,	
	2014	**2013**	**2014**	**2013**
Royalty expense *($000s)*	**808**	1,663	**7,059**	6,785
Per unit *($/boe)*	**0.64**	1.94	**1.47**	2.14
Per unit *($/mcfe)*	**0.11**	0.32	**0.25**	0.36
Royalties as a % of revenue *(%)*	**2.7**	6.1	**4.4**	6.6

For the three months ended December 31, 2014, royalties were $0.8 million, or 2.7% of total revenue, representing a 56% decrease compared to the fourth quarter 2013 royalty rate of 6.1% of total revenue. For the year ended December 31, 2014, royalties were $7.1 million, or 4.4% of total revenue, representing a 33% decrease compared to the year ended December 31, 2013. On a per unit basis, royalties have decreased in both periods as the southeast Saskatchewan assets sold had higher royalty rates than the Corporation's British Columbia properties, where Painted Pony receives average royalty credits of $2.2 million per well.

Painted Pony's producing properties in British Columbia are on Crown lands and in Saskatchewan were on a combination of freehold and Crown lands. Royalties include the Saskatchewan resource charge, which totaled $0.3 million for the year ended December 31, 2014, compared to $0.7 million for the year ended December 31, 2013.

For 2015, the Corporation anticipates overall royalty rates to be less than 4% of total revenues as a result of royalty credits received on revenues generated from British Columbia. This estimate considers the combined impact of incremental sales volumes from newly drilled wells that will qualify for royalty holidays, net of royalties paid on wells that have obtained the full benefit of provincial royalty incentives.

Operating Expenses

	Three months ended December 31,		Year ended December 31,	
	2014	**2013**	**2014**	**2013**
Operating expenses *($000s)*	**9,104**	7,893	**36,804**	29,114
Per unit *($/boe)*	**7.24**	9.21	**7.64**	9.17
Per unit *($/mcfe)*	**1.21**	1.54	**1.27**	1.53

Operating expenses were reduced by $1.97 per boe or 21% in the fourth quarter of 2014 compared to the fourth quarter of 2013. On an annual basis, operating expenses were decreased by $1.53 per boe or 17%.

Per unit operating costs have improved significantly due to the disposition of the Corporation's higher cost Saskatchewan assets combined with incremental production volumes from British Columbia, which positively impacted fixed cost components including equipment rentals, repairs and maintenance, operator costs, lease costs, and fuel and power costs.

For 2015 the Corporation anticipates that per unit operating costs will be approximately $7.50 per boe, assuming normal seasonal weather conditions.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Transportation Costs

	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Transportation costs *($000s)*	**3,761**	2,241	**13,928**	7,296
Per unit *($/boe)*	**2.99**	2.62	**2.89**	2.30
Per unit *($/mcfe)*	**0.50**	0.44	**0.48**	0.38

Transportation costs for the three months ended December 31, 2014 increased by $1.5 million or $0.37 per boe compared to the three months ended December 31, 2013. For the year ended December 31, 2014, transportation costs increased by $6.6 million or $0.59 per boe compared to the year ended December 31, 2013.

The increases are primarily due to higher transportation costs associated with increased NGL volumes in British Columbia at the Corporation's Townsend properties. For 2015 the Corporation expects transportation costs to continue to be approximately $3.00 per boe.

Field Operating Netbacks

British Columbia

($/boe)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Revenue	**23.87**	25.38	**30.51**	23.52
Royalties	**(0.64)**	(0.72)	**(0.93)**	(0.63)
Operating expenses	**(7.40)**	(6.75)	**(6.66)**	(6.58)
Transportation costs	**(2.99)**	(2.69)	**(2.93)**	(2.35)
Field operating netback	**12.84**	15.22	**19.99**	13.96

Saskatchewan

($/boe)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Revenue	**-**	82.95	**98.16**	87.01
Royalties	**-**	(11.25)	**(13.78)**	(11.34)
Operating expenses	**-**	(27.98)	**(29.98)**	(24.97)
Transportation costs	**-**	(2.06)	**(2.04)**	(1.98)
Field operating netback	**-**	41.66	**52.36**	48.72

MANAGEMENT'S DISCUSSION AND ANALYSIS

Total

($/boe)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Revenue	**23.86**	32.05	**33.34**	32.49
Royalties	**(0.64)**	(1.94)	**(1.47)**	(2.14)
Operating expenses	**(7.24)**	(9.21)	**(7.64)**	(9.17)
Transportation costs	**(2.99)**	(2.62)	**(2.89)**	(2.30)
Field operating netback	**12.99**	18.28	**21.34**	18.88

($/mcfe)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Revenue	**3.98**	5.34	**5.56**	5.42
Royalties	**(0.11)**	(0.32)	**(0.25)**	(0.36)
Operating expenses	**(1.21)**	(1.54)	**(1.27)**	(1.53)
Transportation costs	**(0.50)**	(0.44)	**(0.48)**	(0.38)
Field operating netback	**2.17**	3.05	**3.56**	3.15

For the three months ended December 31, 2014, field operating netbacks decreased as a result of lower realized commodity prices, offset by lower per unit royalties and operating costs on the Corporation's British Columbia natural gas assets. For the year ended December 31, 2014, field operating netbacks increased as a result of higher natural gas and natural gas liquids prices combined with lower per unit royalties and operating expenses.

During the three months and year ended December 31, 2014, the Corporation's field operating netbacks were 54% and 64% of revenue, respectively. This compares to 57% and 58%, respectively, for the three months and year ended December 31, 2013.

General and Administrative Expenses

($000s, except per boe and per mcfe)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Gross expense	**7,950**	5,448	**17,922**	14,188
Capitalized	**(2,478)**	(1,596)	**(4,791)**	(3,737)
Capital recoveries	**(1,069)**	(395)	**(2,182)**	(1,317)
Operating recoveries	**(64)**	(123)	**(406)**	(470)
Net expense	**4,339**	3,334	**10,543**	8,664
Per unit *($/boe)*	**3.45**	3.89	**2.19**	2.73
Per unit *($/mcfe)*	**0.58**	0.65	**0.37**	0.46

Net general and administrative ("G&A") expenses increased by $1.0 million and $1.9 million, respectively, for the three months and year ended December 31, 2014 compared to the three months and year ended December 31, 2013. Increases were driven primarily by higher administrative costs related to an increase in the number of employees compared to the same period of 2013. For the three months ended December 31, 2014, bonuses in accordance with Painted Pony's bonus program of $2.0 million were included in net G&A expenses and of $1.7 million were capitalized. For the three months ended December 31, 2013, bonuses of $1.6 million were included in net G&A expenses and of $1.0 million were capitalized.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three months and year ended December 31, 2014, net G&A expenses declined by $0.44 per boe to $3.45 per boe and by $0.54 per boe to $2.19 per boe, respectively, compared to the three months and year ended December 31, 2013. The decreases were driven primarily by increases of 47% and 52% in production volumes for the three months and year ended December 31, 2014, respectively, which offset incremental staffing and associated costs in the period. For 2015, the Corporation expects net G&A expenses to be in the range of $2.00 per boe to $2.50 per boe.

The Corporation's policy of allocating and capitalizing costs associated with new capital projects was unchanged in the fourth quarter and year ended December 31, 2014 compared to the previous year. During the three months ended December 31, 2014 and 2013, the Corporation capitalized $2.5 million and $1.6 million of administrative costs to capital projects, respectively. G&A capital and operating recoveries were in accordance with industry practice and were $1.1 million for three months ended December 31, 2014, compared to $0.5 million for the three months ended December 31, 2013.

Share-Based Compensation Expense

($000s)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Gross expense	**3,021**	2,566	**7,813**	9,447
Capitalized	**(472)**	(325)	**(1,892)**	(2,119)
Net expense	**2,549**	2,241	**5,921**	7,328

Gross share-based compensation expense was $3.0 million for the three months ended December 31, 2014 compared to $2.6 million for the three months ended December 31, 2013. The higher expense was driven by stock options granted during the fourth quarter of 2014 that had a higher fair value than those granted in the fourth quarter of 2013. Gross share-based compensation expense for the year ended December 31, 2014 of $7.8 million was 17% lower than gross share-based compensation expense for the year ended December 31, 2013 of $9.4 million due to the timing of stock option grants throughout the year, as well as lower expenses as a result of options forfeited during the year.

The weighted average fair value of stock options granted during the year using the Black-Scholes model was $3.75 per option, compared to $3.83 per option during 2013.

Share-based compensation expense is a non-cash estimate of the cost of granting options to purchase shares, calculated using a Black-Scholes model. The expense does not represent actual cash compensation realized by the recipients of the options upon the eventual exercise of these options.

Depletion and Depreciation Expense

($000s)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Depletion and depreciation *($000s)*	**9,389**	11,278	**47,593**	42,422
Per unit *($/boe)*	**7.47**	13.16	**9.88**	13.37
Per unit *($/mcfe)*	**1.25**	2.19	**1.65**	2.23

Depletion and depreciation expense for the three months ended December 31, 2014 decreased by $5.69 per boe or 43%, as compared to the same period in 2013. The depletion rate was positively impacted by the disposition of the Corporation's Saskatchewan assets, which historically had a higher depletion rate than its British Columbia assets, combined with a 68% increase in total proved and probable reserves since December 31, 2013. The depletion calculation for the three months ended December 31, 2014 included future development costs associated with the development of the Corporation's proved plus probable reserves of $3.0 billion, compared to $2.4 billion for the three months ended December 31, 2013.

The Corporation's exploration and evaluation assets totaling $120.1 million as at December 31, 2014, compared to $72.5 million as at December 31, 2013, were not subject to depletion.

Depreciation expense was recognized for leasehold improvements, office equipment, computer hardware and software and office furniture on a 20% per annum declining-balance basis.

Exploration and Evaluation Expense

During the three months and year ended December 31, 2014, the Corporation recorded $9.6 million and $13.2 million, respectively, in exploration and evaluation expense primarily consisting of drilling and completion costs spent on the Corporation's Alberta assets as a result of the determination that no further delineation is planned in the near future in this area. During the three months and year ended December 31, 2013, the Corporation recorded $3.6 million and $5.5 million, respectively, in exploration and evaluation expense relating primarily to lease expiries and non-economic drilling activity on the Corporation's Saskatchewan properties. There has been no exploration and evaluation expense associated with the Corporation's British Columbia properties for 2014 or 2013.

Net Finance Expense

	Three months ended December 31,		Year ended December 31,	
($000s)	**2014**	**2013**	**2014**	**2013**
Finance charges	**243**	327	**1,892**	960
Accretion of decommissioning obligations	**88**	128	**455**	415
Interest income	**(187)**	(8)	**(341)**	(267)
Total	**144**	447	**2,006**	1,108

Finance charges include interest expense on bank debt and standby charges on the Corporation's syndicated credit facilities. For the three months ended December 31, 2014, finance charges were lower than in the comparable period of 2013 as a result of the Corporation having been in a cash position for the majority of the quarter. Finance charges for the year also included renegotiation fees on the credit facilities.

Accretion expense on decommissioning obligations has decreased for the three months ended December 31, 2014 as a result of the impact of a lower discount rate used in calculating the present value of the decommissioning obligation. At December 31, 2014, the risk-free interest rate related to the decommissioning obligations was decreased to 2.5% from 3.1% at December 31, 2013.

Interest income for the three months and year ended December 31, 2014 increased compared to the comparative periods of 2013, reflective of increased levels of cash.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Capital Expenditures

($000s)	Three months ended December 31, 2014	2013	Year ended December 31, 2014	2013
Drilling and completions	**51,637**	17,849	**143,287**	73,666
Facilities and equipment	**20,342**	7,533	**44,833**	28,291
Lease acquisitions and retention	**123**	274	**749**	809
Seismic	**152**	-	**390**	824
Exploration and evaluation	**67,231**	9,135	**67,660**	33,061
Capitalized G&A	**2,478**	1,596	**4,791**	3,737
Exploration and development	**141,963**	36,387	**261,710**	140,388
Head office expenditures	**521**	(273)	**1,222**	2,189
Capital expenditures	**142,484**	36,114	**262,932**	142,577
Property acquisitions	**-**	20	**1,155**	258
Share-based compensation	**472**	325	**1,892**	2,119
Decommissioning costs	**1,097**	3,247	**4,509**	1,629
Total	**144,053**	39,706	**270,488**	146,583

During the three months and year ended December 31, 2014, the Corporation invested $142.0 million and $261.7 million, respectively, in exploration and development capital expenditures, compared to $36.4 million and $140.4 million, respectively, for the three months and year ended December 31, 2013.

Capital expenditures for the three months ended December 31, 2014 included $51.6 million spent on drilling and completions activity. The Corporation drilled 7 (6.5 net) Montney natural gas wells in the three month reporting period. Facilities and equipment spending of $20.3 million in the quarter reflects costs related to a 25 MMcf/d (12.5 MMcf/d net) expansion of a Corporation operated natural gas processing facility at Daiber as well as the construction of a 25 MMcf/d natural gas compression and dehydration facility at West Blair. These facilities were fully operational in the first quarter of 2015. Exploration and evaluation expenditures of $67.2 million during the quarter included a $66.8 million crown land acquisition adjacent to the Corporation's Townsend property in British Columbia.

Capital expenditures for 2014 included $143.3 million on drilling and completions activity. During 2014, the Corporation drilled 25 (21.4 net) wells, of which 21 (19.5 net) wells targeted Montney natural gas in British Columbia and 4 (1.9 net) wells targeted crude oil in Saskatchewan. Expenditures on facilities and equipment during the year totalled $44.8 million and included costs related to West Blair facility construction and Daiber facility expansion as well as pipeline costs.

As a result of the current commodity pricing environment, Painted Pony anticipates its 2015 capital program to be $104 million. During 2015, the Corporation intends to drill 14 and complete 11 Montney horizontal natural gas wells wells on its 100% working interest lands in the Blair and Townsend areas.

Property Disposition

On July 30, 2014, the Corporation disposed of its petroleum and natural gas properties in southeast Saskatchewan. The assets had a net book value of $147.6 million and associated decommissioning liabilities of $7.1 million. Consideration consisted of cash of $100 million before closing adjustments. For the year ended December 31, 2014 a loss on disposition, including final adjustments, of $43.4 million was recorded in income.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reserves

		Year ended December 31,	
	2014	**2013**	**Change**
Total proved *(mboe)*	**122,626**	59,878	105%
Total proved + probable *(mboe)*	**488,426**	290,271	68%
Per common share outstanding *(boe/share)*	**4.91**	3.28	50%
Net present value discounted at 10% before tax *($ millions)*	**2,632**	1,502	75%
Per common share outstanding *($/share)*	**26.46**	16.97	56%

GLJ Petroleum Consultants Ltd. ("GLJ"), independent qualified reserves evaluators of Calgary, Alberta, prepared a reserves estimation and economic evaluation of Painted Pony's oil and natural gas properties effective December 31, 2014, which is contained in a report dated February 25, 2015 (the "2014 Reserves Report"). GLJ and Sproule Associates Limited ("Sproule") prepared reserves estimations and economic evaluations of the Corporation's reserves effective December 31, 2013. Reserves estimates stated herein as at December 31 of a year are extracted from the relevant evaluation. The 2014 Reserves Report and the prior reserves evaluation were prepared in accordance with the Canadian Oil & Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

At December 31, 2014, Painted Pony reported year end proved plus probable reserves of 488.4 MMboe representing an increase of 68% from December 31, 2013. Associated with proved plus probable reserve additions was a net present value discounted at 10% of $2.6 billion, which represents a 75% increase over the prior year, despite reduced price forecasts at December 31, 2014 compared to December 31, 2013.

Liquidity and Capital Resources

As at December 31, 2014, the Corporation had positive working capital of $2.8 million. Management anticipates that the Corporation will continue to have adequate liquidity to fund future working capital requirements and capital expenditures through a combination of cash flows and available credit facilities. As a result of the global economic slowdown and current commodity pricing environment, uncertainty exists in the commodity, credit and capital markets, which the Corporation continues to monitor in conjunction with its financing alternatives.

On December 8, 2014 the Corporation's syndicated credit facilities were increased from $150 million to $175 million. The facilities are provided by a syndicate of four Canadian chartered banks, and include a $160 million extendible revolving facility and a $15 million operating facility. The facilities revolve for a 364 day period plus a one year term-out, which is extendible annually, subject to syndicate approval. The facilities are subject to a semi-annual borrowing base review, the next of which is expected to occur on or before May 31, 2015. As at December 31, 2014 the syndicated credit facilities were undrawn.

The credit facilities bear interest on a matrix system that ranges from bank prime plus 1.0% to bank prime plus 3.5% per annum depending on the Corporation's total debt to cash flow ratio as defined by the lender, ranging from less than 1:1 to greater than 3:1. The credit facilities provide that advances may be made by way of prime rate loans, U.S. Base Rate loans, London InterBank Offered Rate loans, bankers' acceptances, letters of credit or letters of guarantee. A standby fee of 0.5% to 0.875% per annum is charged on the undrawn portion of the credit facilities, also calculated depending on the Corporation's total debt to cash flow ratio, as defined by the lender.

Security is provided by a floating charge demand debenture in the principal amount of $300 million on all of the Corporation's assets. The Corporation has provided a negative pledge and undertaking to provide fixed charges over major producing petroleum and natural gas reserves in certain circumstances.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Commitments

($000s)	2015	2016	2017	2018	2019	Thereafter	Total
Gas processing	5,542	4,947	4,147	3,760	2,467	2,366	23,229
Gas gathering	4,257	3,311	2,141	750	-	-	10,459
Office leases	1,596	1,428	1,447	1,466	1,175	-	7,112

Gas processing includes numerous contracts to process natural gas through third party owned gas processing facilities in British Columbia. Gas gathering includes contracts to transport natural gas through third party owned pipeline systems in British Columbia. Office leases include the Corporation's contractual obligations for office space.

On August 18, 2014 the Corporation entered into the Strategic Alliance with AltaGas relating to the development of processing infrastructure and marketing services for natural gas and natural gas liquids. Under the Strategic Alliance, AltaGas is committed to build a number of gas processing facilities for which the field lease work and application process on a 198 MMcf/d shallow cut gas processing facility at the Corporation's Townsend property has commenced. The Corporation will maintain the right to a minimum of 150 MMcf/d of firm capacity at this facility in its first year of operations, increasing to the full 198 MMcf/d in the second year, on each of which there will be a take or pay obligation on a component of the production volumes that will be delivered to the facility upon commencement of commercial operations. The obligation related to the take or pay is not reflected in the above commitment table due to the uncertainty of the timing and ultimate magnitude of the commitment.

Off Balance Sheet Arrangements

The Corporation has certain lease arrangements, all of which are reflected in the commitments table, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

Share Capital

As at December 31, 2014, there were 99,469,775 Common Shares issued and outstanding.

On August 25, 2014 the Corporation completed a private placement with AltaGas of 4,166,666 Common Shares at $12.00 per share for total consideration of $50 million. On December 2, 2014 the Corporation completed a bought deal financing of 5,275,050 Common Shares at $12.00 per share for total gross proceeds of $63.3 million.

The Corporation has an incentive stock option plan (the "Plan") whereby options to purchase Common Shares may be granted by the Board of Directors to directors, officers and employees of the Corporation.

During the year ended December 31, 2014, a total of 2,307,100 options were granted at an average exercise price of $9.50. In 2014, there were 1,571,299 options exercised at an average price of $6.46, and 407,667 options forfeited at an average price of $11.14. During the year ended December 31, 2013, a total of 2,416,500 options were granted at an average exercise price of $7.58. In 2013, there were 405,000 options exercised at an average price of $6.06 and 546,000 options forfeited at an average price of $10.86.

As at December 31, 2014, 8,155,101 options to purchase Common Shares were issued and outstanding at a weighted-average price of $9.17 per option for each Common Share. The options are exercisable over a five year period, with one-third vesting immediately, one-third vesting one year from the date of grant, and one-third vesting two years from the date of grant.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Corporation is authorized to issue an unlimited number of Preferred Shares, issuable in series. As at December 31, 2014 and March 4, 2015, no Preferred Shares were issued or outstanding.

As at March 4, 2015, there were 99,624,775 Common Shares and 7,892,501 options issued and outstanding.

Income Taxes

As at December 31, 2014, the Corporation had a $13.1 million deferred tax asset, compared to $9.4 million as at December 31, 2013. The Corporation recognized deferred income tax recovery of $2.6 million during the year ended December 31, 2014. For the year ended December 31, 2013, the Corporation recognized a deferred income tax expense of $0.6 million.

The Corporation expects that future taxable income will be available to utilize accumulated tax pools. Painted Pony's estimated tax pools at December 31, 2014 are comprised of the following:

Estimated Tax Pools *($000s)*	**As at December 31, 2014**
Canadian exploration expense	81,124
Canadian development expense	248,856
Canadian oil and gas property expense	137,061
Undepreciated cost of capital	79,825
Non-capital losses	143,514
Other	9,315
Total	699,695

Dividends

The Corporation has not declared or paid any dividends and does not intend to do so in the near future.

Performance Compared to Expectations

Readers are reminded that forward-looking statements in this MD&A are subject to significant risks and uncertainties, many of which are beyond Painted Pony's control and are based on a number of material factors and assumptions, some or all of which may prove to be incorrect. A comparison of actual performance to Corporation expectations previously announced is as follows:

- *Average daily production volumes in 2014 were expected to average 13,500 boe/d, weighted 90% towards natural gas. Actual production volumes averaged 13,192 boe/d and were weighted 89% towards natural gas. Volumes during the year were slightly lower than anticipated as a result of facilities commencing operations during the first quarter of 2015 compared to expected commencement during the fourth quarter of 2014, as well as the sale of the Corporation's crude oil assets during the year.*

- *For 2014, the Corporation expected to receive a natural gas price that slightly exceeded the AECO daily spot price as a result of heat content and a differential. The actual weighted average price received during 2014 represented a 1% discount to the AECO reference price. Painted Pony's British Columbia natural gas receives a price determined with reference to the British Columbia Westcoast Station 2 reference price, which experienced a wider differential than expected during the fourth quarter of 2014.*

- *For 2014, the Corporation expected to receive an average crude oil price that was comparable to the Edmonton par reference price. The actual weighted average price received during 2014 represented a 10% premium over this reference price.*

MANAGEMENT'S DISCUSSION AND ANALYSIS

- *Overall royalties in 2014 were expected to average 6% to 7% of total revenues. The actual royalty rate for 2014 was 4.4% of total revenues as the Corporation's crude oil properties in Saskatchewan, which have historically had higher royalty rates, were disposed of in the third quarter of 2014.*
- *Operating expenses for 2014 were expected to be less than $7.50 per boe. Actual operating expenses were $7.64 per boe.*
- *Transportation expenses for 2014 were expected to be less than $3.00 per boe. Actual transportation expenses for the year were $2.89 per boe.*
- *Net G&A expenses in 2014 were expected to be less than $2.00 per boe. Actual net G&A expenses for 2014 were $2.19 per boe, as fourth quarter G&A included staff bonuses for 2014 performance, which exceeded budget expectations.*

Critical Accounting Estimates

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

Impact of Reserves
Estimation of recoverable quantities of proved and probable reserves includes estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in expected future cash flows in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion and depreciation of property, plant and equipment ("PP&E"), and the recognition of deferred tax assets. These reserve estimates are prepared in accordance with the Canadian Oil and Gas Evaluation Handbook and are verified by independent qualified reserve evaluators, who work with information provided by the Corporation to establish reserve determinations in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

The Corporation estimates the decommissioning obligations for petroleum and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of petroleum and natural gas properties based upon the estimation of recoverable quantities of proved and probable reserves being acquired.

Share-Based Compensation
The Corporation's estimate of share-based compensation is dependent upon estimates of historic volatility, risk-free interest rates and forfeiture rates.

Derivative Financial Instruments
The Corporation's estimate of the fair value of any derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

Taxes
The deferred tax asset is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Future Accounting Pronouncements

The following new and revised accounting pronouncements have been issued by the International Accounting Standards Board ("IASB") but are not yet effective. The Corporation has reviewed these pronouncements and as at December 31, 2014 is still determining the impact that the adoption of these standards will have on its financial statements.

As of January 1, 2016 the Corporation will be required to adopt amendments to IFRS 11 "Joint Arrangements", which clarify that business combination accounting is required to be applied to acquisitions of interests in a joint operation that constitutes a business, as well as amendments to IAS 16 "Property, Plant and Equipment", which clarify that revenue-based methods of depreciation cannot be used for property, plant and equipment.

As of January 1, 2017, the Corporation will be required to adopt IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue" and established principles for reporting useful information to user of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers.

As of January 1, 2018, the Corporation will be required to adopt IFRS 9 "Financial Instruments", which replaces IAS 39 "Financial Instruments: Recognition and Measurement" and provides a logical model for classification and measurement, a single, forward looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting.

Changes in Accounting Policies

On January 1, 2014 the Corporation implemented IAS 32 "Financial Instruments: Presentation", which clarifies the requirements for offsetting financial assets and liabilities. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability. On January 1, 2014 the Corporation implemented the IASB issued IFRIC 21 "Levies", which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. On January 1, 2014 the Corporation implemented the amendments to IAS 36, "Impairment of Assets", which require disclosure of information about the recoverable amount of impaired assets.

The adoption of these standards had no impact on the Corporation's financial statements as at and for the year ended December 31, 2014.

Business Risks

Painted Pony's production and exploration activities are concentrated in Western Canada, where activity is highly competitive and includes a variety of companies ranging from smaller junior producers to the much larger integrated producers. Painted Pony is subject to various types of business risks and uncertainties including but not limited to:

- *The availability of qualified personnel and drilling equipment;*
- *Finding and developing petroleum and natural gas reserves at economic costs;*
- *Production of petroleum and natural gas in commercial quantities; and*
- *Marketability of petroleum and natural gas production.*

MANAGEMENT'S DISCUSSION AND ANALYSIS

In order to reduce exploration risk, the Corporation strives to employ highly qualified and motivated professional employees and consultants with a demonstrated ability to generate quality proprietary geological and geophysical prospects. To help maximize drilling success, Painted Pony combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects with some exposure to select high-risk plays with high-reward opportunities. Painted Pony also explores in areas where the Corporation's officers and employees have significant experience.

The Corporation mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems. In addition, Painted Pony seeks operational control of its projects, where feasible.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, Painted Pony conducts its operations with high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Corporation maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations. Painted Pony may periodically use financial or physical delivery hedges to reduce its exposure against the potential adverse impact of commodity price volatility, as governed by formal policies approved by senior management, subject to controls established by the Board of Directors.

Legal, Environmental, Remediation and Other Contingent Matters

The Corporation reviews legal, environmental, remediation and other contingent matters to both determine whether a loss is probable based on judgment and interpretation of laws and regulations, and determine whether the loss can reasonably be estimated. When the loss is determined, it is charged to income. The Corporation's management monitors known and potential contingent matters and makes appropriate provisions by charges to income when warranted by the circumstances.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Corporation has established and maintains internal controls over financial reporting that were designed using the COSO Framework published by the Committee of Sponsoring Organizations of the Treadway Commission. The control framework was designed or caused to be designed under the supervision of the Corporation's CEO and CFO to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in the Corporation's internal controls over financial reporting were identified during the period beginning on October 1, 2014 and ended on December 31, 2014 that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

Selected Consolidated Quarterly Information

The following tables set forth selected consolidated financial information of the Corporation for the eight most recently completed quarters ending at the fourth quarter of 2014.

Quarter ended *($000s, except where noted)*	**March 31, 2014**	**June 30, 2014**	**Sept. 30 2014**	**Dec. 31, 2014**
Petroleum and natural gas revenue[1]	37,235	54,388	38,919	**30,003**
Funds flow from operations	19,450	33,705	23,189	**12,583**
Per share - basic	0.22	0.38	0.25	**0.13**
Per share - diluted	0.22	0.37	0.25	**0.13**
Net income (loss)	(1,511)	(18,923)	8,222	**(3,352)**
Per share - basic and diluted	(0.02)	(0.21)	0.09	**(0.04)**
Cash capital expenditures	45,526	28,098	46,824	**142,484**
Property acquisitions	250	905	-	**-**
Property dispositions	-	-	97,245	**3,756**
Working capital (deficiency)	(41,284)	80,389	63,410	**2,835**
Bank debt	33,354	49,270	-	**-**
Total assets	669,816	649,648	669,495	**737,836**
Decommissioning obligations	17,858	11,461	12,814	**14,258**
Average daily production volumes *(boe/d)*	9,734	15,029	14,283	**13,665**
Average daily production volumes *(mcfe/day)*	58,404	60,116	85,698	**81,990**
Realized prices				
Natural gas *($/mcf)*	5.72	4.97	4.15	**3.54**
Natural gas liquids *($/bbl)*	80.27	89.70	71.26	**58.05**
Crude oil *($/bbl)*	99.41	105.39	101.16	**-**
Field operating netbacks *($/boe)*				
Total *($/boe)*	27.75	27.04	19.12	**12.99**
Total *($/mcfe)*	4.63	4.51	3.19	**2.17**

(1) Before royalties.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Quarter ended *($000s, except where noted)*	**March 31, 2013**	**June 30, 2013**	**Sept. 30, 2013**	**Dec. 31, 2013**
Petroleum and natural gas revenue [1]	25,522	24,644	25,467	27,453
Funds flow from operations	14,118	12,610	12,177	12,322
Per share - basic and diluted	0.16	0.14	0.14	0.14
Net income (loss)	(1,794)	698	(209)	(4,417)
Per share - basic and diluted	(0.02)	0.01	(0.00)	(0.05)
Cash capital expenditures	52,103	14,871	39,489	36,114
Property acquisitions	-	-	238	20
Working capital (deficiency)	9,267	7,324	(20,657)	(16,348)
Bank debt	-	-	-	28,626
Total assets	614,714	595,417	615,935	635,055
Decommissioning obligations	14,582	14,351	13,335	16,482
Average daily production volumes *(boe/d)*	8,596	7,928	8,925	9,312
Average daily production volumes *(mcfe/day)*	51,576	47,568	53,550	55,872
Realized prices				
Natural gas *($/mcf)*	3.34	3.79	2.95	3.76
Natural gas liquids *($/bbl)*	45.79	66.67	72.10	63.47
Crude oil *($/bbl)*	87.70	93.30	105.58	86.88
Field operating netbacks				
Total *($/boe)*	20.63	20.06	16.81	18.28
Total *($/mcfe)*	3.44	3.34	2.80	3.05

(1) Before royalties.

Selected Consolidated Annual Information

The following table sets forth selected consolidated annual financial information of the Corporation for the three most recently completed years ending December 31, 2014.

Years ended *($millions, except volumes and per share)*	**Dec. 31, 2014**	**Dec. 31, 2013**	**Dec. 31, 2012**
Petroleum and natural gas revenue [1]	**160.5**	103.1	74.8
Funds flow from operations	**88.9**	51.2	39.3
Basic, per share	**0.97**	0.58	0.56
Diluted, per share	**0.97**	0.58	0.55
Net loss	**(15.6)**	(5.7)	(48.1)
Basic and diluted, per share	**(0.17)**	(0.06)	(0.68)
Cash capital expenditures	**262.9**	142.6	118.6
Property acquisitions	**1.2**	0.3	115.1
Property dispositions	**101.0**	-	-
Working capital (deficiency)	**2.8**	(16.3)	45.2
Bank debt	**-**	28.6	-
Total assets	**737.8**	635.1	612.2
Decommissioning obligations	**14.3**	16.5	14.8
Average daily production volumes *(boe/day)*	**13,192**	8,693	6,589
Average daily production volumes *(mcfe/day)*	**79,152**	52,128	39,534

MANAGEMENT'S DISCUSSION AND ANALYSIS

Significant factors and trends that have affected the Corporation's results during the above annual and quarterly periods include:

- *Petroleum and natural gas revenues are impacted by both fluctuating commodity prices and production volumes. The Corporation's successful capital program has generated incremental production volumes and higher cash flows. The commodity prices realized by the Corporation have approximated the AECO daily spot gas prices and Edmonton par light oil prices with periodic widening of differentials throughout the above periods. The reference price fluctuations reflect changes in supply and demand by commodity, both internationally and domestically.*

- *Funds flow from operations reflects the impact of fluctuating commodity prices on a growing production base. Operating and transportation cost variations track seasonal weather-related issues combined with fixed commitments. Throughout 2012 and early 2013, natural gas and crude oil prices weakened, while commodity prices increased in late 2013 and throughout 2014. Royalties vary due to commodity prices, production levels and the status of provincial royalty incentive programs. As the production base matures, incremental royalties occur on wells as the maximum volumes provided for under provincial incentive programs are attained.*

- *The net loss in 2014 is attributable to the $43.4 million loss recorded on disposition of the Saskatchewan assets as well as a $13.2 million exploration and evaluation expense related to Saskatchewan and Alberta assets. The net loss in 2013 was primarily attributable to exploration and evaluation expense of $5.5 million, and the 2012 net loss was primarily attributable to a $42.1 million impairment of property, plant and equipment on Saskatchewan assets.*

- *Fluctuations in capital expenditures have reflected both available capital resources and capital spending restraints during weaker commodity price cycles.*

- *As the Corporation's focus has shifted from exploration to development, working capital has decreased and the Corporation has begun utilizing bank debt. As a result of the asset disposition, private placement and bought deal financing completed during 2014, the Corporation had no bank debt and a working capital position of $2.8 million as at December 31, 2014.*

- *Total assets and non-current liabilities have increased as the Corporation's capital program has been executed.*

Advisories

Forward-looking Statements

Certain statements in this MD&A constitute forward-looking statements and forward-looking information (collectively, the "forward-looking statements") within the meaning of applicable Canadian securities laws. Such forward-looking statements relate to future events including expectations of future production, components of cash flow and net income, expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. All statements other than statements of historical fact contained in this MD&A may be forward-looking statements. Such statements and information may be identified by words such as "anticipate", "will", "intend", "could", "should", "may", "might", "expect", "forecast", "plan", "potential", "project", "assume", "contemplate", "believe", "budget", "shall", "continue", "milestone", "target", "vision", "forward looking to", and similar terms or the negatives thereof or other comparable terminology. The forward-looking statements contained in this MD&A involve known and unknown risks, uncertainties and other factors that are beyond the Corporation's control, which may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, this MD&A contains forward looking information relating to estimates of recoverable reserves volumes and the future net revenues associated with those reserves.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The forward-looking statements contained in this MD&A represent management's reasonable projections, expectations and estimates as of the date of this document, but undue reliance should not be placed upon them as they are derived from numerous assumptions. In addition, forward-looking statements may include statements or information attributable to third party industry sources. These assumptions are subject to known and unknown risks and uncertainties, including the business risks discussed in this MD&A and the risks discussed in the Corporation's AIF for the year ended December 31, 2013, many of which are beyond Painted Pony's control and which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Additionally, there can be no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

The forward-looking statements in this MD&A are subject to significant risks and uncertainties, many of which are beyond Painted Pony's control and are based on a number of material factors and assumptions, certain or all of which may prove to be incorrect including, but not limited to, the following:

- *production volumes in 2015 will meet forecasted levels;*
- *the Corporation will receive a natural gas price that varies in concert with Westcoast Station 2 pricing;*
- *overall royalties for 2015 will be less than 4% of total revenues;*
- *average per unit operating expenses in 2015 are expected to be approximately $7.50 per boe, assuming normal seasonal weather conditions;*
- *average per unit transportation costs in 2015 are expected to be approximately $3.00 per boe;*
- *net G&A expenses are expected to average between $2.00 per boe and $2.50 per boe in 2015;*
- *the Corporation has sufficient financial resources with which to conduct its capital program assuming that the drilling rigs, field service providers and completion and tie-in equipment will be available as required and that the costs of securing such services and equipment will not materially exceed expectations;*
- *available credit facilities will continue to be utilized in 2015;*
- *data used by GLJ in their independent reserves evaluation is valid;*
- *commitments to process and transport natural gas through third party owned facilities and pipeline systems are expected to be fulfilled;*
- *agreements to lease office space are expected to be adhered to; and*
- *the risk of accounts receivable becoming uncollectible is mitigated by the financial position of the applicable entities.*

Certain or all of the foregoing assumptions may prove to be incorrect and, while it is anticipated that subsequent events and developments may cause the Corporation's views to change, there is no intention to update the forward-looking statements, except as required by applicable securities laws. These forward-looking statements represent the Corporation's views as of the date of this MD&A and such information should not be relied upon as representing the Corporation's views as of any date subsequent to the date of this MD&A. The Corporation has attempted to identify important factors that could cause actual results, performance or achievements to vary from those current expectations or estimates expressed or implied by the forward-looking statements contained herein. However, there may be other factors that cause results, performance or achievements not to be as expected or estimated and that could cause actual results, performance or achievements to differ materially from current expectations.

Other risks and uncertainties include, but are not limited to, the following:

- *normal risks common to the oil and gas industry, including exploration, development and production operations risks;*
- *volatility of commodity prices;*
- *changes in interest and foreign exchange rates;*
- *risks and uncertainty of petroleum and natural gas geological deposits and reserves estimates;*
- *health, safety and environmental risks;*
- *revisions, amendments or changes to capital expenditure plans including exploration, development and exploitation projects;*
- *uncertainty of estimates and projections of production and costs;*
- *risks as to the availability and pricing of appropriate financing alternatives on acceptable terms;*
- *potential changes in income tax regulations, governmental policies, rules, practices or approval process changes, or delays, or enhancements;*
- *delays resulting from adverse weather conditions;*
- *delays resulting from an inability to obtain required regulatory approvals and ability to access sufficient debt or equity capital from internal and external sources; and*
- *the Corporation's ability to attract and retain qualified professional employees and consultants.*

Statements relating to "reserves" or "resources" are by their nature deemed to be forward-looking statements, as they involve the implied assessment based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

There can be no assurance that forward-looking statements will prove to be accurate, as results and future events could differ materially from those expected or estimated in such statements. Accordingly, readers should not place undue reliance on forward-looking statements. From time to time, Painted Pony's management makes estimates and forms opinions on which the forward-looking statements are based. The Corporation assumes no obligation to update forward-looking statements if circumstances, management's estimates, or opinions change, unless prescribed by securities laws. Furthermore, readers should be aware that historical results are not necessarily indicative of future performance.

Forecast Prices and Costs

Reserves estimates stated herein are calculated using the forecast price and cost assumptions by the reserves evaluator which were in effect at the time of the applicable reserves evaluation. The complete GLJ January 1, 2015 price forecast is available on its website at gljpc.com. At the time of the 2014 Reserves Evaluation the Corporation's 2015 capital expenditure budget was $295 million and forecast expenditures in future years that may vary from actual expenditures.

Gross Reserves

Unless otherwise stated, references to "reserves" are to the Corporation's gross reserves, defined as the Corporation's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Estimated Future Net Revenues

Estimated future net revenues are stated before deducting income taxes and future estimated site restoration costs and are reduced for estimated future abandonment costs and estimated capital for future development associated with the reserves. The undiscounted and discounted net present values disclosed do not represent the fair market value of the reserves.

Potential Transactions

Within its focus area, the Corporation is always reviewing potential property acquisitions and corporate mergers and acquisitions for the purpose of determining whether any such potential transaction is of interest to the Corporation, as well as the terms on which such a potential transaction would be available. As a result, the Corporation may from time to time be involved in discussions or negotiations with other parties or their agents in respect of potential property acquisitions and corporate merger and acquisition opportunities. The Corporation is not committed to any such potential transaction and cannot be reasonably confident that it can complete any such potential transaction until appropriate legal documentation has been signed by the relevant parties.

BOE Conversions

Barrel of oil equivalent amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel of oil (1 bbl). Boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

MCFE Conversions

Thousands of cubic feet of gas equivalent amounts have been calculated by using the conversion ratio of one barrel of oil (1 bbl) to six thousand cubic feet (6 Mcf) of natural gas. Mcfe amounts may be misleading, particularly if used in isolation. A conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Abbreviations

Natural Gas

mcf	*thousand cubic feet*
mcf/d	*thousand cubic feet per day*
mmcf/d	*million cubic feet per day*
boe	*barrels of oil equivalent*
boe/d	*barrels of oil equivalent per day*
mboe	*thousand barrels of oil equivalent*

Natural Gas Liquids

bbls	*barrels*
bbls/d	*barrels per day*
NGLs	*natural gas liquids*
mcfe	*thousand cubic feet equivalent*
mcfe/d	*thousand cubic feet equivalent per day*

Additional Information

Additional information regarding the Corporation and its business and operations, including the AIF for the year ended December 31, 2013 is available on the Corporation's SEDAR profile at www.sedar.com. Copies of the Corporation's disclosure can also be obtained by contacting the Corporation at Painted Pony Petroleum Ltd., 1800, 736 - 6 Avenue SW., Calgary, Alberta T2P 3T7 (Phone (403) 475-0440), by email at info@paintedpony.ca or on the Corporation's website at www.paintedpony.ca.

MANAGEMENT'S RESPONSIBILITY FOR CONSOLIDATED FINANCIAL STATEMENTS

Management of Painted Pony Petroleum Ltd. (the "Corporation") is responsible for the preparation and integrity of the accompanying consolidated financial statements and all other information contained in this report. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") and include amounts that are based on management's informed judgments and estimates where necessary.

The Corporation has established internal accounting control systems which are designed to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of the consolidated financial statements together with the other financial information for external purposes in accordance with IFRS.

The Board of Directors, through its Audit Committee, monitors management's financial and accounting policies and practices and the preparation of these consolidated financial statements. The Audit Committee meets periodically with the external auditors and management to review the work of each and the propriety of the discharge of their responsibilities.

The Audit Committee reviews the consolidated financial statements of the Corporation with management and the external auditors prior to submission to the Board of Directors for final approval. The Board of Directors also reviews the consolidated financial statements before they are finalized. The Board of Directors has approved the consolidated financial statements for the years ended December 31, 2014 and 2013.

The external auditors have full and free access to the Audit Committee to discuss auditing and financial reporting matters. The Audit Committee reviews the independence of the external auditors and pre-approves audit and permitted non-audit services and fees. The Shareholders have appointed KPMG LLP as the external auditors of the Corporation, and in that capacity, they have audited the consolidated financial statements for the years ended December 31, 2014 and 2013.

Patrick R. Ward	John H. Van de Pol
President and CEO	*Senior Vice President and CFO*

March 4, 2015

INDEPENDENT AUDITOR' REPORT

To the Shareholders of Painted Pony Petroleum Ltd.

We have audited the accompanying consolidated financial statements of Painted Pony Petroleum Ltd. which comprise the consolidated statements of financial position as at December 31, 2014 and December 31, 2013, the consolidated statements of operations, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Painted Pony Petroleum Ltd. as at December 31, 2014 and December 31, 2013, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants

March 4, 2015
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(000s) As at	December 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 30,715	$ -
Trade and other receivables	20,714	16,647
Prepaid expenses and deposits	929	544
Fair value of risk management contracts *(note 13)*	5,130	42
	57,488	17,233
Non-current assets		
Fair value of risk management contracts *(note 13)*	-	36
Exploration and evaluation *(note 4)*	120,078	72,482
Property, plant and equipment *(note 5)*	547,168	535,862
Deferred tax *(note 12)*	13,102	9,442
	$ 737,836	$ 635,055
LIABILITIES		
Current liabilities		
Trade and other payables	$ 54,653	$ 33,581
Non-current liabilities		
Bank debt *(note 6)*	-	28,626
Decommissioning obligations *(note 7)*	14,258	16,482
	68,911	78,689
EQUITY		
Share capital *(note 9)*	680,820	554,149
Contributed surplus	45,544	44,092
Deficit	(57,439)	(41,875)
	668,925	556,366
	$ 737,836	$ 635,055

Commitments *(note 16)*
Subsequent event *(note 13)*

The notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board:

Arthur J. G. Madden
Director

Patrick R. Ward
Director

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years ended December 31, 2014	2013
Revenue		
Petroleum and natural gas	$ **160,545**	$ 103,086
Royalties	**(7,059)**	(6,785)
	153,486	96,301
Realized loss on commodity risk management *(note 13)*	**(3,284)**	-
Unrealized gain on commodity risk management *(note 13)*	**5,052**	78
	155,254	96,379
Expenses		
Operating	**36,804**	29,114
Transportation	**13,928**	7,296
General and administrative	**10,543**	8,664
Share-based compensation *(note 9)*	**5,921**	7,328
Depletion and depreciation *(note 5)*	**47,593**	42,422
Exploration and evaluation *(note 4)*	**13,198**	5,534
Loss on disposition of assets *(note 4 and 5)*	**43,404**	-
	171,391	100,358
Results from operating activities	**(16,137)**	(3,979)
Net finance expense *(note 10)*	**2,006**	1,108
Loss before income tax	**(18,143)**	(5,087)
Deferred income tax (expense) recovery *(note 12)*	**2,579**	(635)
Net loss and comprehensive loss	$ **(15,564)**	$ (5,722)
Net loss per share *(note 8)*:		
Basic and diluted	$ **(0.17)**	$ (0.06)

The notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(000s, except shares)

Years ended December 31, 2014 and 2013

	Number of Shares	Share Capital	Contributed Surplus	Retained Earnings/ (Deficit)	Total Equity
Balance at December 31, 2012	88,051,760	$ 550,116	$ 36,226	$ (36,153)	$ 550,189
Share-based compensation	-	-	9,447	-	9,447
Options exercised *(note 9)*	405,000	4,033	(1,581)	-	2,452
Net loss	-	-	-	(5,722)	(5,722)
Balance at December 31, 2013	88,456,760	554,149	44,092	(41,875)	556,366
Issue of shares *(note 9)*	9,441,716	113,300	-	-	113,300
Share issue costs, net of tax of $1,081	-	(3,146)	-	-	(3,146)
Share-based compensation	-	-	7,813	-	7,813
Options exercised *(note 9)*	1,571,299	16,517	(6,361)	-	10,156
Net loss	-	-	-	(15,564)	(15,564)
Balance at December 31, 2014	99,469,775	$ 680,820	$ 45,544	$ (57,439)	$ 668,925

The notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years ended December 31, 2014	2013
Cash flows from operating activities:		
Net loss and comprehensive loss	$ (15,564)	$ (5,722)
Adjustments for:		
Depletion and depreciation expense	47,593	42,422
Exploration and evaluation expense	13,198	5,534
Share-based compensation	5,921	7,328
Net finance expense	2,006	1,108
Deferred income tax expense (recovery)	(2,579)	635
Unrealized gain on commodity risk management	(5,052)	(78)
Loss on disposition of assets	43,404	-
Decommissioning expenditures *(note 7)*	(798)	(383)
Changes in non-cash working capital *(note 11)*	2,174	(1,731)
	90,303	49,113
Cash flows from investing activities:		
Property, plant and equipment additions	(195,272)	(109,516)
Property, plant and equipment acquisitions	(1,155)	(258)
Exploration and evaluation additions	(67,660)	(33,061)
Property, plant and equipment dispositions *(notes 4 and 5)*	101,001	-
Changes in non-cash working capital *(note 11)*	14,390	(13,935)
	(148,696)	(156,770)
Cash flows from financing activities:		
Issue of share capital	113,300	-
Share issuance costs	(4,227)	-
Exercise of share options	10,156	2,452
Increase in (repayment of) bank debt	(28,626)	28,626
Net cash finance expense	(1,551)	(693)
Changes in non-cash working capital *(note 11)*	56	(250)
	89,108	30,135
Change in cash and cash equivalents	30,715	(77,522)
Cash and cash equivalents, beginning of year	-	77,522
Cash and cash equivalents, end of year	$ 30,715	$ -

The notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

1. Reporting Entity

Painted Pony Petroleum Ltd.'s ("Painted Pony" or the "Corporation") principal business activity is the exploration, development and production of petroleum and natural gas resources in western Canada. The consolidated financial statements of the Corporation as at and for the years ended December 31, 2014 and 2013 include the accounts of the Corporation and its wholly owned subsidiary, Painted Rock Resources Ltd. The Corporation's head office is located at 736 - 6th Avenue S.W., Suite 1800, Calgary, Alberta.

2. Basis of Presentation

(a) Statement of Compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements were authorized for issuance by the Board of Directors of the Corporation on March 4, 2015.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair value are discussed in note 14.

(c) Functional and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the Corporation's and its subsidiary's functional currency.

(d) Use of Judgments and Estimates

The preparation of consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ materially from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis, with revisions to accounting estimates recognized in the period in which the estimates are changed and in any applicable future periods.

Critical Accounting Judgments

The following are critical judgments that management has made in the process of applying accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements.

(i) Cash Generating Units ("CGU" or "CGUs")

The Corporation's assets are aggregated into cash-generating units for the purpose of assessing impairment. CGUs are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment in regard to shared infrastructure, geographical proximity, petroleum type and exposure to market risk and materiality.

(ii) Impairment

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future petroleum and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

The application of the Corporation's accounting policy for exploration and evaluation ("E&E") assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

(iii) Taxes

In determining its deferred tax provisions, the Corporation must apply judgment when interpreting and applying tax laws and regulations. The determination of the appropriate rules may be uncertain for many periods. The final outcome could result in amounts different from those initially recorded and could impact tax expense in the periods where a determination is made.

Judgments are also made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable income.

Critical Accounting Estimates

The following are key estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

(i) Impact of Reserves

Estimation of recoverable quantities of proved and probable reserves includes estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in expected future cash flows in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of E&E assets and the amounts reported for depletion and depreciation of property, plant and equipment ("PP&E"), and the recognition of deferred tax assets. These reserve estimates are prepared in accordance with the Canadian Oil and Gas Evaluation Handbook and are verified by independent qualified reserve evaluators, who work with information provided by the Corporation to establish reserve determinations in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

The Corporation estimates the decommissioning obligations for petroleum and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of petroleum and natural gas properties based upon the estimation of recoverable quantities of proved and probable reserves being acquired.

(ii) Share-Based Compensation

The Corporation's estimate of share-based compensation is dependent upon estimates of historic volatility, risk-free interest rates and forfeiture rates.

(iii) Derivative Financial Instruments

The Corporation's estimate of the fair value of any derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

(iv) Taxes

The deferred tax asset is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements, by both the Corporation and its subsidiary.

(a) Basis of Consolidation

Subsidiaries
Subsidiaries are entities controlled by the Corporation. Control exists when the Corporation has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statement of operations.

Jointly Controlled Operations and Jointly Controlled Assets
A portion of the Corporation's petroleum and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Corporation's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

Transactions Eliminated on Consolidation
Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Financial Instruments

Non-derivative Financial Instruments
Non-derivative financial instruments comprise cash and cash equivalents, trade and other receivables, trade and other payables and bank debt. Non-derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through comprehensive income or loss, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash and cash equivalents comprise cash on hand, term deposits held with banks and other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts that are repayable on demand form part of the Corporation's cash management whereby management has the ability and intent to net bank overdrafts against cash, and are included as a component of cash and cash equivalents, for the purpose of the statements of cash flows.

Other non-derivative financial instruments include trade and other receivables, trade and other payables and bank debt. Trade and other receivables are measured using the effective interest rate method, less any impairment losses. Trade and other payables are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Bank debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

Derivative Financial Instruments

The Corporation has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Corporation has not designated its financial derivative contracts as effective accounting hedges and, therefore, has not applied hedge accounting, even though the Corporation considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the statements of financial position at fair value. Transaction costs are recognized in net income when incurred.

(c) Exploration and Evaluation Assets and Property, Plant and Equipment

Recognition and Measurement

(I) Exploration and Evaluation Assets

Pre-licence costs are expensed as incurred. E&E costs, including the costs of acquiring licenses, seismic, exploration drilling and directly attributable general and administrative costs initially are capitalized as E&E assets according to the nature of the assets acquired. The costs are accumulated in cost centers pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. A review is carried out, on a quarterly basis, to ascertain whether proved or probable reserves have been discovered. Upon determination of proved or probable reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E assets.

(ii) Property, Plant and Equipment

Items of PP&E, which include petroleum and natural gas development and production assets, are measured at cost less accumulated depletion, depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of PP&E, including petroleum and natural gas interests, have different useful lives, they are accounted for as separate items.

Gains and losses on disposal of an item of PP&E, are determined by comparing the proceeds from disposal, or fair value or properties received, with the carrying amount of the asset(s) and are recognized in income.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as petroleum and natural gas interests only when they increase the future economic benefits embodied in the specific assets to which they relate. All other expenditures are recognized in comprehensive income or loss as incurred. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves. The carrying amount of any replaced or sold component is derecognized. The costs of periodic servicing of PP&E are recognized in income.

Depletion and Depreciation

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers on an annual basis, at a minimum.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

Proved and probable reserves are estimated using independent reserve engineer reports in accordance with NI 51-101 and represent the estimated quantities of petroleum, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for proved reserve components are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- *a reasonable assessment of the future economics of such production;*
- *a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and*
- *evidence that the necessary production, transmission and transportation facilities are available or can be made available.*

In determining reserves for use in the depletion and impairment calculations, a barrel of oil equivalent ("boe") conversion ratio of six thousand cubic feet of gas ("Mcf") to one barrel of oil ("bbl") (6 Mcf:1 bbl) is used as an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in the reserve report are derived by converting natural gas to crude oil in the ratio of six Mcf of gas to one barrel of crude oil.

Reserves may only be considered proved and probable if producibility is supported by either actual production or a conclusive formation test. The area of reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of petroleum and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

For other assets, depreciation is recognized in comprehensive income or loss on a declining-balance rate of 20% based on their estimated useful lives. E&E assets are not depreciated.

(d) Impairment

Financial Assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in income.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in income.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

Non-financial Assets

The carrying amounts of the Corporation's non-financial assets, other than E&E assets and deferred tax assets, are reviewed whenever there is an indication of impairment. If any such indication exists, the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into CGUs, being the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing fair value less costs to sell, 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. Fair value less costs to sell is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

E&E assets are assessed for impairment if: (i) sufficient data exists to determine technical feasibility and commercial viability, or (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in income. For purposes of impairment testing, E&E assets are combined with cash-generating units.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(e) Leased Assets

Payments made under operating leases are recognized in comprehensive income or loss on a straight-line basis (or as otherwise contractually defined) over the term of the lease. Lease incentives received are recognized as part of the total lease expense over the term of the lease.

Leases which transfer substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to the asset. Minimum lease payments are apportioned between the finance expense and the reduction of the outstanding liability. The finance expense is allocated to each period during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

(f) Share Capital

Common Shares are classified as equity. Incremental costs directly attributable to the issue of shares and share options are recognized as a deduction from equity, net of tax.

(g) Share-Based Compensation

The Corporation has issued options to acquire Common Shares to directors, officers and employees. The fair value of options on the date they are granted is recognized as compensation expense with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. The Corporation uses the Black-Scholes model to estimate fair value.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax risk free rate.

Decommissioning Obligations

The Corporation's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and is capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance cost whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision had been established.

(i) Revenue Recognition

Revenue from the sale of petroleum and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer, which is usually when legal title passes to the external party, and when collection is reasonably assured.

Tariffs and tolls charged to other entities for use of pipelines and facilities owned by the Corporation are recognized as revenue as they accrue in accordance with the terms of the service or tariff and tolling agreements.

(j) Finance Income and Expenses

Finance income comprises interest income.

Finance expense consists of interest expense and standby fees on credit facilities, costs related to the implementation of the credit facilities and accretion on the decommissioning obligation.

(k) Income Tax

Income tax expense comprises deferred income tax expense and is recognized in income except to the extent that it relates to items recognized directly in equity.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

(l) Foreign Currency Translation

The principal currency of the economic environment in which the Corporation and its wholly owned subsidiary operate is the Canadian dollar. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at exchange rates in effect at the end of the period, and revenues and expenses are translated into Canadian dollars at average exchange rates. All translation gains and losses are recorded to income.

(m) Income (loss) per Share

Basic income (loss) per share is calculated on the basis of the weighted average number of Common Shares outstanding during the period. Diluted income (loss) per share reflects the potential dilutive effect of options. Anti-dilutive instruments are not included in the determination of diluted income (loss) per share.

(n) Future Accounting Pronouncements

The following new and revised accounting pronouncements have been issued by the International Accounting Standards Board ("IASB") but are not yet effective. The Corporation has reviewed these pronouncements and as at December 31, 2014 is still determining the impact that the adoption of these standards will have on its financial statements.

As of January 1, 2016 the Corporation will be required to adopt amendments to IFRS 11 "Joint Arrangements", which clarify that business combination accounting is required to be applied to acquisitions of interests in a joint operation that constitutes a business, as well as amendments to IAS 16 "Property, Plant and Equipment", which clarify that revenue-based methods of depreciation cannot be used for PP&E.

As of January 1, 2017, the Corporation will be required to adopt IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue" and established principles for reporting useful information to user of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers.

As of January 1, 2018, the Corporation will be required to adopt IFRS 9 "Financial Instruments", which replaces IAS 39 "Financial Instruments: Recognition and Measurement" and provides a logical model for classification and measurement, a single, forward looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting.

(o) Changes in Accounting Policies

On January 1, 2014 the Corporation implemented IAS 32 "Financial Instruments: Presentation", which clarifies the requirements for offsetting financial assets and liabilities. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability.

On January 1, 2014 the Corporation implemented the IASB issued IFRIC 21 "Levies", which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. On January 1, 2014 the Corporation implemented the amendments to IAS 36, "Impairment of Assets", which require disclosure of information about the recoverable amount of impaired assets.

The adoption of these standards had no impact on the Corporation's financial statements as at and for the year ended December 31, 2014.

4. Exploration and Evaluation Assets

(000s)		
Cost:		
Balance, December 31, 2012	$	68,707
Additions		33,061
Transfer to property, plant and equipment		(23,752)
Expensed		(5,534)
Balance, December 31, 2013	$	72,482
Additions		67,660
Transfer to property, plant and equipment		(3,248)
Dispositions		(3,618)
Expensed		(13,198)
Balance, December 31, 2014	$	120,078

E&E assets consist of undeveloped lands and unevaluated seismic data on the Corporation's exploration projects which are pending the determination of proved or probable reserves. Additions represent the Corporation's share of costs incurred on E&E assets during the year. During the year ended December 31, 2014, the Corporation recorded E&E additions that included $66.8 million on a crown land acquisition in the fourth quarter on 2014. Transfers are made to PP&E as proved or probable reserves are determined. E&E assets are expensed due to non-economic drilling and completion activities and lease expiries. The Corporation assesses the recoverability of E&E assets as the transfer to PP&E is considered.

5. Property, Plant and Equipment

(000s)		
Cost:		
Balance, December 31, 2012	$	576,570
Acquisitions		258
Cash additions		109,516
Non-cash additions		3,748
Transfer from exploration and evaluation		23,752
Balance, December 31, 2013	$	713,844
Acquisitions		1,155
Cash additions		195,272
Non-cash additions		7,061
Transfer from exploration and evaluation		3,248
Dispositions		(236,682)
Balance, December 31, 2014	$	683,898

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

(000s)		
Accumulated depletion and depreciation:		
Balance, December 31, 2012	$	135,560
Depletion and depreciation		42,422
Balance, December 31, 2013	$	177,982
Depletion and depreciation		47,593
Dispositions		(88,845)
Balance, December 31, 2014	$	136,730
Carrying amounts:		
December 31, 2013	$	535,862
December 31, 2014	$	547,168

Estimated future development costs associated with the development of the Corporation's proved plus probable reserves at December 31, 2014 were $3.0 billion, compared to $2.4 billion at December 31, 2013.

(a) Property Disposition

On July 30, 2014, the Corporation disposed of certain petroleum and natural gas properties with a net book value of $147.6 million and associated decommissioning liabilities of $7.1 million. Consideration consisted of cash of $100 million before closing adjustments. These properties were held for sale as of June 30, 2014 and a loss on disposition of $43.4 million, including final adjustments, was recognized during the year ended December 31, 2014. Included in the three months ended December 31, 2014 are other dispositions of $3.8 million.

(b) Capitalized General and Administrative Expense, Recoveries and Share-Based Compensation

Years ended December 31, *(000s)*		**2014**		**2013**
General and administrative	**$**	**4,791**	$	3,737
Capital recoveries		**2,182**		1,317
Share-based compensation		**1,892**		2,119
Total	**$**	**8,865**	$	7,173

(c) Other Assets

The total cost associated with office furniture and fixtures and leasehold improvements at December 31, 2014 was $4.6 million, with accumulated depreciation of $1.4 million. This compares to a cost of $3.4 million as at December 31, 2013, with accumulated amortization of $0.8 million.

6. Bank Debt

On December 8, 2014 the Corporation's syndicated credit facilities were increased from $150 million to $175 million. The facilities are provided by a syndicate of four Canadian chartered banks, and include a $160 million extendible revolving facility and a $15 million operating facility. The facilities revolve for a 364 day period plus a one year term-out, which is extendible annually, subject to syndicate approval. The facilities are subject to a semi-annual borrowing base review, the next of which is expected to occur on or before May 31, 2015. As at December 31, 2014 the syndicated credit facilities were undrawn.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

The credit facilities bear interest on a matrix system which ranges from bank prime plus 1.0% to bank prime plus 3.5% per annum depending on the Corporation's total debt to cash flow ratio as defined by the lender, ranging from less than 1:1 to greater than 3:1. The credit facilities provide that advances may be made by way of prime rate loans, U.S. Base Rate loans, London InterBank Offered Rate loans, bankers' acceptances, letters of credit or letters of guarantee. A standby fee of 0.5% to 0.875% per annum is charged on the undrawn portion of the credit facilities, also calculated depending on the Corporation's total debt to cash flow ratio, as defined by the lender.

Security is provided by a floating charge demand debenture in the principal amount of $300 million on all of the Corporation's assets. The Corporation has provided a negative pledge and undertaking to provide fixed charges over major producing petroleum and natural gas reserves in certain circumstances.

7. Decommissioning Obligations

Years ended December 31, *(000s)*	**2014**	2013
Balance, beginning of year	**$ 16,482**	$ 14,821
Provisions	**3,130**	1,104
Revisions	**2,039**	525
Dispositions	**(7,050)**	-
Decommissioning expenditures	**(798)**	(383)
Accretion	**455**	415
Balance, end of year	**$ 14,258**	$ 16,482

The Corporation's decommissioning obligations result from its ownership interest in petroleum and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Corporation's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Corporation has estimated the net present value of the decommissioning obligations based on an undiscounted total future liability of $33.7 million, compared to $36.0 million at December 31, 2013, with payments expected to be made over the next 14 to 50 years. The discount factor, being the risk-free rate related to the liability at December 31, 2014, was 2.5%, compared to 3.1% at December 31, 2013, and the inflation rate was 2% at both December 31, 2014 and 2013.

8. Net Loss per Share

Years ended December 31,	**2014**	2013
Net loss *(000s)*	**$ (15,564)**	$ (5,722)
Weighted average common shares - basic and diluted	**91,244,920**	88,420,058
Net loss per share - basic and diluted	**$ (0.17)**	$ (0.06)

The average market value of the Corporation's Common Shares for purposes of determining the dilutive effect of outstanding stock options was based on quoted market prices for the period. During the years ended December 31, 2014 and 2013, all options were excluded from the weighted-average diluted share calculation of Common Shares.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

9. Share Capital

(a) Authorized

The Corporation has an unlimited number of Common and Preferred Shares authorized for issuance. At December 31, 2014 there were 99,469,775 Common Shares outstanding, compared to 88,456,760 Common Shares outstanding at December 31, 2013. At December 31, 2014 and December 31, 2013 there were no Preferred Shares outstanding.

On August 25, 2014 the Corporation completed a private placement of 4,166,666 Common Shares at $12.00 per share for total consideration of $50 million. On December 2, 2014 the Corporation completed a bought deal financing of 5,275,050 Common Shares at $12.00 per share for total gross proceeds of $63.3 million.

The Common Shares entitle the holder thereof to one vote for every share held. There are no fixed dividends payable on the Common Shares. In the event of the liquidation or dissolution of the Corporation, the Common Shares are entitled to receive, on a pro rata basis, all assets of the Corporation as are distributable to the holders of shares.

(b) Stock Options

The Corporation has an option program that entitles employees, officers and directors to purchase Common Shares in the Corporation. Stock options are granted at the market price of the shares at the date of grant, have a five year term and vest one-third immediately with the balance over two years.

The number and weighted average exercise prices of stock options are as follows:

	Weighted Average Exercise Price	Number
Balance, December 31, 2012	$ 9.05	6,361,467
Granted	7.58	2,416,500
Exercised	6.06	(405,000)
Forfeited	10.86	(546,000)
Balance, December 31, 2013	$ 8.63	7,826,967
Granted	9.50	2,307,100
Exercised	6.46	(1,571,299)
Forfeited	11.14	(407,667)
Balance, December 31, 2014	$ 9.17	8,155,101

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

The following table summarizes information about stock options outstanding at December 31, 2014:

Number of Options Outstanding	Exercise Price *($)*	Remaining Life *(yrs)*	Exercisable Options	Exercise Price *($)*
144,167	5.88	0.0	144,167	5.88
383,200	6.51	0.7	383,200	6.51
889,000	10.60	1.3	889,000	10.60
354,000	12.10	1.4	354,000	12.10
30,000	11.19	1.5	30,000	11.19
500,800	11.80	1.9	500,800	11.80
440,700	7.56	2.3	440,700	7.56
80,000	7.10	2.4	80,000	7.10
375,000	10.86	2.7	375,000	10.86
426,300	10.59	2.9	426,300	10.59
360,000	10.33	3.0	240,000	10.33
359,000	10.13	3.3	237,666	10.13
1,511,834	6.44	4.0	989,334	6.44
296,000	8.44	4.2	96,666	8.44
66,000	10.64	4.4	22,000	10.64
154,000	12.17	4.5	51,333	12.17
210,000	14.14	4.7	70,000	14.14
1,575,100	8.78	4.9	525,033	8.78
8,155,101	9.17	3.1	5,855,199	9.28

The Corporation accounts for its stock options granted to employees, officers and directors using the fair value method. In accordance with the Corporation's incentive stock plan, these options have an exercise price equal to the fair value of the Corporation's Common Shares at the date of grant.

The weighted-average fair values of the options granted and the assumptions used in the Black-Scholes option pricing model were as follows:

Years ended December 31,	2014	2013
Fair value per option	$ **3.75**	$ 3.83
Volatility *(%)*	**42**	56
Option life *(years)*	**5**	5
Dividends	**-**	-
Risk-free interest rate *(%)*	**1.95**	1.63

A forfeiture rate of 8% was used when measuring share-based compensation, compared to 7% for December 31, 2013.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

10. Net Finance Expense

Years ended December 31, *(000s)*		**2014**		**2013**
Finance expense:				
Interest and financing costs	**$**	**1,892**	$	960
Accretion of decommissioning obligations		**455**		415
		2,347		1,375
Finance income:				
Interest income		**(341)**		(267)
Net finance expense	**$**	**2,006**	$	1,108

11. Supplemental Cash Flow Information

Changes in non-cash working capital are comprised of:

Years ended December 31, *(000s)*		**2014**		**2013**
Source/(use) of cash:				
Trade and other receivables	**$**	**(4,067)**	$	(2,220)
Prepaid expenses and deposits		**(385)**		(106)
Trade and other payables		**21,072**		(13,590)
		16,620		(15,916)
Operating activities		**2,174**		(1,731)
Investing activities		**14,390**		(13,935)
Financing activities		**56**		(250)
	$	**16,620**	$	(15,916)

12. Deferred Income Tax

Reconciliation of effective tax rate:

Years ended December 31, *(000s)*		**2014**		**2013**
Loss before income tax	**$**	**(18,143)**	$	(5,087)
Combined corporate tax rate		**25.56%**		25.60%
Expected income tax reduction	**$**	**(4,638)**	$	(1,302)
Non-deductible expenses		**28**		22
Non-deductible share-based compensation		**1,564**		1,961
Change in statutory tax rates		**68**		(46)
Other		**399**		-
Total income tax expense (recovery)	**$**	**(2,579)**	$	635

Deferred tax assets and liabilities are attributable to the following:

December 31, *(000s)*	**2014**	2013
Deferred tax liabilities:		
PP&E and E&E assets	**$ (28,296)**	$ (19,500)
Fair value of financial instruments	**(1,311)**	(20)
	(29,607)	(19,520)
Less deferred tax assets:		
Decommissioning obligations	**3,644**	4,234
Share issue costs	**2,101**	2,240
Finance costs	**156**	-
Non-capital losses	**36,808**	22,488
Net deferred tax asset	**$ 13,102**	$ 9,442

The Corporation has non-capital losses of $143.5 million. Of these losses, 99% expire beginning in the year 2030. Based on a reserve report prepared by external reservoir evaluators, the Corporation has determined that it is probable that these losses will be utilized against future taxable income.

Movement in deferred tax balances during the year:

(000s)	PP&E and E&E	Fair value of Financial Instruments	Provisions	Share Issue Costs	Finance Costs	Non-capital Losses	Total
Balance, December 31, 2012	$ (5,613)	-	$ 3,794	$ 3,436	-	$ 8,460	$ 10,077
Recognized in comprehensive income	(13,887)	(20)	440	(1,196)	-	14,028	(635)
Balance, December 31, 2013	$ (19,500)	$ (20)	$ 4,234	$ 2,240	-	$ 22,488	$ 9,442
Recognized in comprehensive income	(8,796)	(1,291)	(590)	(1,220)	156	14,320	2,579
Recognized directly in equity	-	-	-	1,081	-	-	1,081
Balance, December 31, 2014	$ (28,296)	$ (1,311)	$ 3,644	$ 2,101	$ 156	$ 36,808	$ 3,102

13. Financial Instruments and Risk Management

The Corporation's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities. These include market risk, credit risk and liquidity risk.

The Board of Directors of the Corporation oversees management's establishment and execution of the Corporation's risk management framework. Management has implemented and monitors compliance with risk management policies. The Corporation's risk management policies are established to identify and analyze the risks faced by the Corporation, to set appropriate risk limits and controls and to monitor risks and adherence to market conditions and the Corporation's activities.

(a) Market Risk:

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates, will affect the Corporation's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

Natural gas prices obtained by the Corporation are influenced by both US and Canadian supply and demand and an anticipated increased demand for liquefied natural gas. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Corporation for its petroleum and natural gas sales. Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollars, but also upon world economic events that dictate the levels of supply and demand.

The Corporation's production is usually sold through near term sales contracts with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Corporation, however, may give consideration in certain circumstances to the appropriateness of entering into long term fixed price marketing contracts. The majority of the Corporation's natural gas is sold to one purchaser monthly on a best-efforts basis.

The Corporation uses financial derivatives and physical delivery sales contracts to mitigate some of the exposure to commodity price risk, and provide a level of stability to operating cash flows which enables the Corporation to fund its capital development program. The use of these transactions is governed by and is subject to risk management policies established by the Board of Directors of the Corporation.

These instruments are not used for trading or speculative purposes. The Corporation has not designated its financial derivative contracts as effective accounting hedges, even though the Corporation considers all commodity contracts to be effective economic hedges. As a result, all such commodity contracts are recorded at fair value on the statement of financial position, with changes in the fair value being recognized as an unrealized gain or loss on the statement of operations.

Financial assets and liabilities carried at fair value are required to be classified into a hierarchy that prioritizes the inputs used to measure the fair value. The Corporation's risk management contracts are valued using Level 2 inputs. Assets and liabilities in Level 2 are based on valuation models and techniques where the significant inputs are derived from quoted indices.

Commodity Price Contracts

At December 31, 2014, the Corporation held commodity price contracts summarized as follows:

Natural Gas Financial Swaps

Reference	Volume *(mcf/d)*	Term	Weighted Average Price *($/mcf)*	Option Traded	Fair Value *(000s)*
CDN$ AECO	4,739	April 2014 - March 2015	4.06	Swap	503
CDN$ AECO	33,175	January - March 2015	4.42	Swap	4,627
Total fair value					$ 5,130

Subsequent to December 31, 2014, the Corporation re-priced certain commodity price contracts for the remainder of their term, and entered into additional commodity risk management contracts. At March 4, 2015 the Corporation held commodity price contracts summarized as follows:

Reference	Volume *(mcf/d)*	Term	Weighted Average Price *($/mcf)*	Option Traded
CDN$ AECO	37,914	February - March 2015	3.18	Swap
CDN$ AECO	18,957	April - December 2015	3.24	Swap
CDN$ AECO	18,957	April 2015 - March 2017	3.05	Swap

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

For the year ended December 31, 2014, if natural gas prices had been US$0.10 per Mcf higher, with all other variables held constant, the net loss for the year would have been $1.4 million lower. An equal and opposite impact would have occurred to net loss had natural gas prices been US$0.10 per Mcf lower. For the year ended December 31, 2014, if natural gas liquids prices had been US$1 per barrel higher, with all other variables held constant, net loss for the year would have been $0.3 million lower. An equal and opposite impact would have occurred to net loss had natural gas liquids prices been US$1 per barrel lower.

Foreign currency exchange risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Substantially all of the Corporation's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars, however, Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. In the year ended December 31, 2014, if interest rates had been 0.5% lower with all other variables held constant, net loss for the year would have been $0.1 million lower. An equal and opposite impact would have occurred to net loss had interest rates been 0.5% higher.

(b) Credit Risk:

Credit risk is the risk of financial loss to the Corporation if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Corporation's receivables from joint venture partners and petroleum and natural gas purchasers. The Corporation's maximum exposure to credit risk at December 31, 2014 and 2013 is as follows:

Carrying amount, December 31, *(000s)*		**2014**		**2013**
Cash and cash equivalents	**$**	**30,715**	$	-
Trade and other receivables		**20,714**		16,647
Fair value of financial instruments		**5,130**		78
Total	**$**	**56,559**	$	16,725

Cash and Cash Equivalents:

Cash is comprised of bank balances. Historically the Corporation has not carried short term investments Should this change in the future, counterparties will be selected based on credit ratings, management will monitor all investments to ensure a stable return and complex investment vehicles with higher risk will be avoided. The Corporation's exposure to cash credit risk at December 31, 2014 is very low.

Trade and Other Receivables:

All of the Corporation's operations are conducted in Canada. The Corporation's exposure to credit risk is influenced mainly by the individual characteristics of each customer.

Receivables from petroleum and natural gas purchasers are normally collected on the 25th day of the month following production. The Corporation's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Corporation historically has not experienced any collection issues with its petroleum and natural gas purchasers. Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Corporation attempts to mitigate the risk from joint venture receivables by obtaining partner pre-approval. However, the receivables are from participants in the oil and gas sector and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners if a disagreement were to arise, which may increase the potential for non-collection. The Corporation does not typically obtain collateral from petroleum and natural gas purchasers or joint venture partners; however, the Corporation does have the ability to withhold joint venture partners' share of production from operated wells in the event of non-payment.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

The Corporation does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. As such, a provision for doubtful accounts has not been recorded at either December 31, 2014 or 2013.

The breakdown of trade and other receivables at the reporting date by type of customer was:

Carrying amount, December 31, *(000s)*		**2014**		**2013**
Petroleum and natural gas revenue	**$**	**9,007**	$	10,012
Joint interest		**9,188**		3,467
Other		**2,519**		3,168
Total	**$**	**20,714**	$	16,647

The Corporation has one primary purchaser of natural gas in British Columbia; these purchases accounted for $6.7 million of trade and other receivables at December 31, 2014, compared to $8.8 million from major purchasers as at December 31, 2013.

As at December 31, 2014 and 2013, the Corporation's trade and other receivables are aged as follows:

Carrying amount, December 31, *(000s)*		**2014**		**2013**
Less than 30 days	**$**	**20,345**	$	16,067
From 31 - 90 days		**173**		308
More than 90 days		**196**		272
Total	**$**	**20,714**	$	16,647

Derivatives:
The use of financial swap agreements involves a degree of credit risk that the Corporation manages through its risk management policies which are designed to limit eligible counterparties to those with investment grade credit ratings or better.

(c) Liquidity Risk:
Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they become due. The Corporation's approach to managing liquidity is to ensure, to the extent possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Corporation's reputation.

Management closely monitors cash flow requirements to ensure that is has sufficient cash on demand or borrowing capacity to meet operational and financial obligations currently and in the foreseeable future; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Corporation prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Corporation utilizes authority for expenditures on both operated and non-operated projects to further manage capital expenditures. The Corporation also typically collects its petroleum and natural gas revenues from most properties on the 25th of each month.

To facilitate the capital expenditure program, the Corporation has an aggregate of $175 million in syndicated credit facilities at December 31, 2014 compared to $125 million at December 31, 2013, which are reviewed semi-annually by its lenders. At December 31, 2014 the facilities were unutilized, compared to $28.6 million utilized at December 31, 2013.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

(d) Capital Management:

The Corporation's policy is to maintain a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Corporation manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Corporation considers its capital structure to include shareholders' equity, loans and borrowings and working capital. In order to maintain or adjust the capital structure, the Corporation may issue shares and adjust its capital spending to manage current and projected debt levels.

The Corporation monitors capital based on the ratio of net debt to annualized cash flow. This ratio is calculated as net debt, defined as outstanding loans and borrowings plus or minus working capital, divided by cash flow from operations before changes in non-cash working capital and decommissioning expenditures for the most recent calendar quarter and then annualized. The Corporation's objective is to maintain a net debt to annualized cash flow ratio of less than 2:1, with a targeted ratio of 1.5:1. In order to facilitate the management of this ratio, the Corporation prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors of the Corporation.

As a result of shifting from an exploration-focused program to a development-focused program, the Corporation has adapted its approach to capital management to include low cost bank debt as part of the capital structure going forward. Neither the Corporation nor its subsidiary is subject to externally imposed capital requirements. The syndicated credit facilities are subject to a periodic review of the borrowing base which is directly impacted by the value of the petroleum and natural gas reserves.

14. Determination of Fair Values

A number of the Corporation's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(a) Exploration and Evaluation Assets and Property, Plant and Equipment

The fair values of PP&E and E&E assets recognized in an acquisition, are based on market values. The fair values of PP&E and E&E are the estimated amounts for which they could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of petroleum and natural gas interests (included in PP&E) and E&E assets is estimated with reference to the discounted cash flows expected to be derived from petroleum and natural gas production, based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

(b) Cash and Cash Equivalents, Trade and Other Receivables, Trade and Other Payables and Bank Debt

The fair value of cash and cash equivalents, trade and other receivables, trade and other payables and bank debt are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2014 and December 31, 2013, the fair value of these balances approximated their carrying value. Bank debt has a floating rate of interest and therefore the carrying value approximates the fair value.

(c) Stock Options

The fair value of employee stock options is measured using a Black-Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility, weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividends and the risk-free interest rate.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2014 and 2013

(d) Derivatives

The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the date of the statement of financial position, using the remaining contracted petroleum and natural gas volumes and risk-free interest rate (based on published government rates).

Measurement

The Corporation classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

(i) Level 1: Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

(ii) Level 2: Pricing inputs are other than quoted prices in active markets included in Level 1. Prices are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

(iii) Level 3: Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The Corporation's commodity price contracts are valued using Level 2 of the hierarchy.

15. Supplementary Disclosures

(a) Key Management Personnel Compensation

Key management personnel are persons who have the authority and responsibility for planning, directing and controlling the activities of the Corporation, directly or indirectly. This includes all directors and executives of the Corporation. Short-term compensation includes salaries, bonuses and short-term benefits paid to executives and fees paid to directors. Share-based compensation represents the amortization of share-based payment expense associated with options granted to executives and directors.

Years ended December 31, *(000s)*		**2014**		**2013**
Short-term compensation	**$**	**4,597**	$	4,327
Share based compensation		**4,606**		5,631
Total	**$**	**9,203**	$	9,958

(b) Income Statement Presentation

In the Corporation's financial statements, items are primarily disclosed by nature except for employee compensation costs which are included in general and administrative expenses, operating expenses and share based compensation expenses. In the year ended December 31, 2014, employee compensation costs of $12.1 million were included in general and administrative expenses and share based compensation expense, compared to $11.7 million in the year ended December 31, 2013. In the year ended December 31, 2014 employee compensation costs of $1.6 million were included in operating expenses, compared to $1.0 million in the year ended December 31, 2013.

16. Commitments

($000s)	2015	2016	2017	2018	2019	Thereafter	Total
Gas processing	5,542	4,947	4,147	3,760	2,467	2,366	23,229
Gas gathering	4,257	3,311	2,141	750	-	-	10,459
Office leases	1,596	1,428	1,447	1,466	1,175	-	7,112

Gas processing includes numerous contracts to process natural gas through third party owned gas processing facilities in British Columbia. Gas gathering includes contracts to transport natural gas through third party owned pipeline systems in British Columbia. Office leases include the Corporation's contractual obligations for office space.

On August 18, 2014 the Corporation entered into a series of agreements (collectively the "Strategic Alliance") with AltaGas Ltd. ("AltaGas") relating to the development of processing infrastructure and marketing services for natural gas and natural gas liquids. Under the Strategic Alliance, AltaGas is committed to build a number of gas processing facilities for which the field lease work and application process on a 198 MMcf/d shallow cut gas processing facility at the Corporation's Townsend property has commenced. The Corporation will maintain the right to a minimum of 150 MMcf/d of firm capacity at this facility in its first year of operations, increasing to the full 198 MMcf/d in the second year, on each of which there will be a take or pay obligation on a component of the production volumes that will be delivered to the facility upon commencement of commercial operations. The obligation related to the take or pay is not reflected in the above commitment table due to the uncertainty of the timing and ultimate magnitude of the commitment.

NOTES:

CORPORATE INFORMATION

BOARD OF DIRECTORS

Glenn R. Carley
Independent Director and Chairman of the Board
Member of the Compensation Committee and Governance Committee

Kevin D. Angus
Independent Director
Chairman of the Compensation Committee
Member of the Reserves Committee

Allan K. Ashton
Independent Director
Chairman, of the Reserves Committee
Member of the Compensation Committee

Nereus L. Joubert
Independent Director
Member of the Audit Committee and the Governance Committee

Arthur J. G. Madden
Independent Director
Chairman of both the Audit Committee and the Governance Committee

Patrick R. Ward
Director

Peter A. Williams
Independent Director
Member of the Audit Committee

OFFICERS

Patrick R. Ward
President & Chief Executive Officer

John H. Van de Pol
Senior Vice President & Chief Financial Officer

Edwin S. (Ted) Hanbury
Senior Vice President, Engineering

Tonya L. Fleming
Vice President & General Counsel

Bruce G. Hall
Vice President, Land

Stuart W. Jaggard
Vice President & Controller

L. Barry McNamara
Vice President, Corporate Development

James D. Reimer
Vice President, Geoscience & Technology

EXCHANGE LISTING

The Toronto Stock Exchange
Trading symbol for Common Shares: PPY

AUDITORS

KPMG LLP

BANKERS

National Bank of Canada
Alberta Treasury Branches
Canadian Imperial Bank of Commerce
The Bank of Nova Scotia

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada

HEAD OFFICE

1800, 736 - 6 Ave SW
Calgary, Alberta T2P 3T7
Phone: (403) 475-0440
Fax: (403) 238-1487
Toll Free Investor: 1 (866) 975-0440
Email: info@paintedpony.ca
www.paintedpony.ca

Designed by Sandy Seifert. Printed by McAra Printing.

PAINTED PONY
PETROLEUM LTD.

1800, 736 - 6 Ave SW,
Calgary, Alberta T2P 3T7
Phone: (403) 475-0440
Fax: (403) 238-1487
Toll Free: 1-866-975-0440
www.paintedpony.ca