PERPETUAL ENERGY

2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL AND OPERATING HIGHLIGHTS ($CDN thousands, except volume and per Common Share amounts)	Three months ended December 31			Year ended December 31		
	2011	2010	% change	**2011**	2010	% change
FINANCIAL						
Revenue (1) (2)	**63,986**	111,150	(42)	**253,150**	417,093	(39)
Funds flow (2)	**15,893**	70,509	(77)	**76,986**	237,470	(68)
Per Common Share (2) (3)	**0.11**	0.48	(77)	**0.52**	1.69	(69)
Cash flow provided by operating activities	**9,750**	80,210	(88)	**60,428**	199,882	(70)
Per Common Share (2) (3)	**0.07**	0.54	(87)	**0.41**	1.42	(71)
Net loss	**(38,691)**	(28,193)	37	**(95,920)**	(100,719)	(5)
Per Common Share (basic and diluted) (3)	**(0.26)**	(0.19)	37	**(0.65)**	(0.72)	(10)
Dividends declared	-	16,273	(100)	**28,865**	78,628	(63)
Per Common Share (4)	-	0.11	(100)	**0.195**	0.56	(65)
Payout ratio (%) (2)	-	23.1	(100)	**37.2**	33.1	12
Total assets	**1,018,089**	1,027,266	(1)	**1,018,089**	1,027,266	(1)
Net bank debt outstanding (2) (5)	**137,689**	214,546	(36)	**137,689**	214,546	(36)
Senior notes, measured at principal amount	**150,000**	-	100	**150,000**	-	100
Convertible debentures, measured at principal amount	**234,897**	234,897	-	**234,897**	234,897	-
Total net debt (2) (5)	**522,586**	449,443	16	**522,586**	449,443	16
Shareholders' equity	**81,558**	203,904	(60)	**81,558**	203,904	(60)
Capital expenditures						
Exploration and development	**38,269**	38,158	-	**139,214**	115,202	21
Gas storage	**327**	11,171	(97)	**11,207**	57,587	(80)
Acquisitions, net of dispositions	**(2,746)**	(34,253)	(92)	**(33,953)**	50,958	(166)
Other	**97**	332	(71)	**588**	707	(17)
Net capital expenditures	**35,947**	15,408	133	**117,056**	224,454	(48)
SHARES OUTSTANDING (thousands)						
End of year	**146,966**	148,284	(1)	**146,966**	148,284	(1)
Weighted average – basic	**146,905**	147,742	(1)	**147,694**	140,624	5
Diluted	**146,905**	147,742	(1)	**147,694**	140,624	5
March 1, 2012	**146,990**			**146,990**		
OPERATING						
Production						
Average daily natural gas (MMcf/d) (6)	**126.8**	135.9	(7)	**130.2**	145.1	(10)
Average daily oil and natural gas liquids ("NGL") (bbl/d) (6)	**2,685**	1,535	75	**2,027**	1,245	63
Average daily (MMcfe/d) (6)	**142.9**	145.1	(2)	**142.3**	152.6	(7)
Gas over bitumen deemed production (MMcf/d) (7)	**27.4**	24.2	13	**26.4**	24.8	6
Average daily (actual and deemed – MMcfe/d) (6) (7)	**170.3**	169.3	1	**168.7**	177.4	(5)
Per Common Share (cubic feet equivalent/d/Common Share) (3)	**1.16**	1.15	1	**1.14**	1.26	(10)
Average prices						
Natural gas – before derivatives ($/Mcf) (8)	**3.35**	3.87	(13)	**3.77**	4.17	(10)
Natural gas – including derivatives ($/Mcf) (8)	**3.31**	7.83	(58)	**3.82**	7.10	(46)
Oil and NGL – before derivatives ($/bbl) (8)	**79.16**	75.88	4	**73.90**	68.29	8
Oil and NGL – including derivatives ($/bbl) (8)	**91.63**	75.88	21	**78.06**	68.29	14

FINANCIAL AND OPERATING HIGHLIGHTS CONTINUED

	Three Months Ended December 31			Year Ended December 31		
	2011	2010	% change	**2011**	2010	% change
RESERVES (Bcfe)						
Company interest – proved [9] [10]	**235.1**	250.4	(6)	**235.1**	250.4	(6)
Company interest - proved and probable [9] [10]	**484.7**	487.7	(1)	**484.7**	487.7	(1)
Per Common Share (Mcfe/Common Share) [12]	**3.30**	3.29	-	**3.30**	3.29	-
Estimated present value before tax ($ millions) [11]						
Proved	**431.6**	581.8	(26)	**431.6**	581.8	(26)
Proved and probable	**722.4**	928.2	(22)	**722.4**	928.2	(22)
LAND (thousands of net acres)						
Total land holdings	**3,313**	3,421	(3)	**3,313**	3,421	(3)
Undeveloped land holdings	**1,849**	1,905	(3)	**1,849**	1,905	(3)
DRILLING (wells drilled gross/net)						
Gas	**5/5.0**	3/2.4	67/108	**16/15.5**	48/44.3	(67)/(65)
Oil	**10/10.0**	3/1.0	233/900	**35/34.0**	14/11.6	150/193
Gas storage	**-/-**	-/-	-/-	**3/3.0**	6/6.0	(50)/(50)
Service	**-/-**	1/1.0	(100)/(100)	**1/1.0**	1/1.0	-/-
Oilsands evaluation	**-/-**	-/-	-/-	**7/7.0**	-/-	100/100
Dry	**-/-**	-/-	-/-	**-/-**	1/1.0	(100)/(100)
Total	**15/15.0**	7/4.4	114/241	**62/60.5**	70/63.9	(11)/(5)
Success rate	**100/100**	100/100	-/-	**100/100**	99/98	1/2

(1) Revenue includes realized gains and losses on derivatives and call option premiums received.

(2) This is a non-GAAP measure; please refer to "Significant accounting policies and non-GAAP measures" included in Management's Discussion and Analysis.

(3) Based on weighted average Common Shares outstanding for the period.

(4) Based on Common Shares outstanding at each dividend payment date.

(5) Net bank debt is measured as at the end of the period and includes net working capital (deficiency), excluding short-term derivative assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, assets and liabilities held for sale and the share based payment liability. Total net debt includes senior notes and convertible debentures, measured at principal amount.

(6) Production amounts are based on the Corporation's interest before deduction of royalties.

(7) Deemed production describes all gas shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the Alberta Energy and Utilities Board ("AEUB"), or through correspondence in relation to an AEUB ID 99-1 application. This deemed production is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution received monthly from the Alberta Crown as a reduction of other royalties payable. See "Gas over bitumen royalty adjustments" in Management's Discussion and Analysis.

(8) Perpetual's commodity hedging strategy employs both financial forward contracts and physical commodity delivery contracts at fixed prices or price collars.

(9) As evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") in accordance with National Instrument 51-101. See "Reserves" included in this Management's Discussion and Analysis.

(10) Reserves are presented on a company interest basis, including working interest and royalty interest volumes but before royalty burdens.

(11) Discounted at ten percent using McDaniel's forecast pricing. Reserves at various other discount rates are located in the "Reserves" section of Management's Discussion and Analysis. Estimated present value amounts should not be taken to represent an estimate of fair market value.

(12) Based on Common Shares outstanding at period end.

<u>MANAGEMENT'S DISCUSSION AND ANALYSIS</u>

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual" or the "Corporation") operating and financial results for the year ended December 31, 2011 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2011 and 2010. Perpetual's financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, which replaced previously generally accepted accounting principles in Canada ("Previous GAAP") on January 1, 2011 with a transition date of January 1, 2010. Comparative figures for the year ended December 31, 2009 included in this MD&A were prepared in accordance with Previous GAAP. Readers are referred to the Transition to IFRS section of this MD&A, and the advisories regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information" section of this MD&A. The date of this MD&A is March 12, 2012.

Mcf equivalent ("Mcfe") and barrel of oil equivalent ("BOE") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for oil of 1 bbl: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. For natural gas, gigajoules ("GJ") are converted to Mcf at a conversion ratio of 1.0546 GJ: 1 Mcf.

CORPORATE

Perpetual is an oil and natural gas exploration and production company headquartered in Calgary, Alberta. The Corporation has been actively transitioning its asset base from primarily shallow gas production to a diversified, resource-style growth-oriented platform for growth. Perpetual currently has liquids-rich natural gas assets in the Deep Basin of west central Alberta, heavy oil production in eastern Alberta, a natural gas storage facility and oilsands leases in northern Alberta to complement its shallow gas production base.

On June 30, 2010, Perpetual announced that the Corporation had completed the previously announced plan of arrangement (the "Arrangement") involving Perpetual, Paramount Energy Trust (the "Trust") and Paramount Energy Operating Corp. pursuant to which the Trust converted into the Corporation. Unitholders of the Trust voted in favor of the Arrangement at the Annual General and Special Meeting of Trust Unitholders held on June 17, 2010. Former Unitholders of the Trust received common shares of Perpetual in consideration for the cancellation of their Trust Units on a one-for-one basis. In addition, as part of the Arrangement, the Trust was dissolved and the Corporation assumed all of the existing liabilities of the Trust, including the Trust's outstanding convertible debentures which are now convertible debentures of the Corporation.

References to "Common Shares" and "Shareholders" are references to the securities of the Corporation and the holders thereof following the conversion date, and references to "dividends" are references to dividends paid by Perpetual following the conversion date and to distributions paid by the Trust prior to the conversion date, as the context may require.

NON-GAAP MEASURES

Funds flow

The Corporation charges exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties and the cost of expired leases to earnings or loss in the period incurred. To make reported funds flow in this MD&A more comparable to industry practice the Corporation reclassifies dry hole costs, geological and geophysical costs and expired leases from operating to investing activities in the funds flow reconciliation.

Management uses cash flow provided by operating activities before changes in non-cash working capital, gas over bitumen royalty adjustments not yet received, settlement of decomissioning obligations and certain exploration and evaluation costs described above ("funds flow"), funds flow per common share and annualized funds flow to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable to the calculation of similar measures for other entities. Funds flow as presented is not intended to represent operating profits for the period nor should it be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP.

Funds flow is reconciled to its closest GAAP measure, cash flow provided by operating activities, as follows.

Funds flow GAAP reconciliation	**For the three months ended December 31**		**For the year ended December 31**	
($ thousands, except per Common Share amounts)	**2011**	2010	**2011**	2010
Cash flow provided by operating activities	**9,750**	80,210	**60,428**	199,882
Exploration and evaluation costs [(1)]	**960**	1,483	**3,917**	4,030
Expenditures on decommissioning obligations	**(1,867)**	1,201	**2,514**	4,880
Gas over bitumen royalty adjustments not yet received (received)	**(281)**	1,393	**564**	3,357
Distributions expensed through loss	**-**	-	**-**	40,549
Changes in non-cash operating working capital	**7,331**	(13,778)	**9,563**	(15,228)
Funds flow	**15,893**	70,509	**76,986**	237,470
Funds flow per Common Share [(2)]	**0.11**	0.48	**0.52**	1.69

(1) Certain exploration and evaluation costs are added back to funds flow in order to be more comparable to other Corporations that capitalize some of these costs. Exploration and evaluation costs that are added back to funds flow include geological and geophysical expenditures and dry hole costs and are considered by Perpetual to be more closely related to investing activities than operating activities.

(2) Based on weighted average Common Shares outstanding for the period.

Additional non-GAAP measures are discussed elsewhere in this MD&A.

FOURTH QUARTER 2011 RESULTS

Fourth quarter information	**Three months ended December 31**		
($ thousands except as noted)	**2011**	2010	% change
Average daily production volumes			
Natural gas (MMcf/d)	**126.8**	135.9	(7)
Oil & NGL (bbl/d)	**2,685**	1,535	75
Total (MMcfe/d)	**142.9**	145.1	(2)
Actual plus deemed production (MMcfe/d)	**170.3**	169.3	1
Natural gas revenue	**39,093**	48,412	(19)
Oil and NGL revenue	**19,552**	10,711	83
Gas storage revenue	**2,768**	2,595	7
Realized gains (losses) on derivatives	**(550)**	49,432	(101)
Call option premiums received	**3,123**	-	100
Oil and natural gas revenue, after derivatives	**63,986**	111,150	(42)
AECO Monthly Index ($/Mcf)	**3.44**	3.58	(4)
Natural gas price, before derivatives ($/Mcf)	**3.35**	3.87	(13)
Realized natural gas price ($/Mcf)	**3.31**	7.83	(58)
WTI Average Price ($US/bbl)	**89.67**	90.77	(1)
Oil and NGL price, before derivatives ($/bbl)	**79.16**	75.88	4
Realized oil and NGL price ($/bbl)	**91.63**	75.88	21
Royalties	**4,185**	2,727	53
Royalties as a percentage of oil, NGL and natural gas revenues (%)	**7.1**	4.6	54
Operating expenses	**25,393**	20,826	22
Per Mcfe	**1.93**	1.56	24
Cash general and administrative (“G&A”) expenses	**7,918**	9,286	(15)
Per Mcfe	**0.60**	0.70	(14)
Funds flow	**15,893**	70,509	(77)
Per Common Share	**0.11**	0.48	(77)
Cash flow provided by operating activities	**9,750**	80,210	(88)
Per Common Share	**0.07**	0.54	(87)
Net loss	**(38,691)**	(28,193)	37
Per Common Share	**(0.26)**	(0.19)	37

Capital expenditures – exploration and development	**38,269**	38,158	-
Capital expenditures – gas storage	**327**	11,171	(97)

In comparing the three months ended December 31, 2011 with the fourth quarter of 2010:

Capital expenditures

- Exploration and development expenditures were consistent at $38.3 million for the fourth quarter of 2011 compared to $38.2 million for 2010. Perpetual expanded its 2011 capital budget in the second half of 2011 to accelerate the development of its liquids-rich Wilrich assets in west central Alberta and its heavy oil program at Birchwavy. In total nine horizontal and one vertical oil wells and four horizontal Wilrich wells were drilled with a 100 percent success rate. Perpetual also drilled a high-impact exploratory well at West Edson which was completed in January 2012, completed the tie-in of a horizontal Dunvegan development well drilled in the third quarter, and expanded its acreage position in the Mannville heavy oil play.

Production & Pricing

- Oil and NGL production increased 75 percent to 2,685 bbl/d due to successful Wilrich liquids-rich gas and Mannville heavy oil drilling programs in 2011. Natural gas production declined seven percent to 126.8 MMcf/d due to natural declines, non-core asset dispositions, and the shut-in of natural gas production and subsequent sale of assets at Liege in November 2010, partially offset by production additions from Karr and Wilrich drilling activities. Perpetual became eligible to receive the gas over bitumen financial compensation for the Liege assets in June 2011, and therefore total actual plus deemed production increased one percent from the fourth quarter of 2010 to 170.3 MMcfe/d for the current period.

- Natural gas prices before derivatives declined 13 percent to $3.35 per Mcf due to lower AECO Monthly Index prices and the inclusion of 10,000 GJ/d of fixed price physical natural gas sales at $7.75 per GJ for November to December 2010 in the previous quarter's price. Realized gas prices decreased 58 percent to $3.31 per Mcf, as natural gas hedging gains totaled $49.4 million for the three months ended December 31, 2010. In anticipation of a low natural gas price environment in 2011, Perpetual crystallized $37.3 million in gains on derivatives in the fourth quarter of 2010 related to 2011 financial natural gas contracts. Perpetual's oil & NGL price before derivatives increased four percent to $79.16 per bbl from $75.88 per bbl for the comparative period in 2010. Including derivatives, Perpetual realized an average oil and NGL price in the fourth quarter of 2011 of $91.63 per bbl.

Financial

- Funds flow decreased 77 percent to $15.9 million for the current quarter primarily due to lower realized gains on derivatives and higher operating costs. The positive impact of the Corporation's ongoing commodity diversification strategy was reflected in the fourth quarter as an increase in the liquids component of the Corporation's production mix contributed to keeping oil and natural gas revenues relatively flat, despite a decline in total production volumes from quarter to quarter.

- The Corporation's royalty rate of 7.1 percent of revenues was higher than the fourth quarter of 2010, as the prior period amount included $1.5 million in royalty recoveries related to previous years.

- Cash G&A expenses decreased $1.4 million from the fourth quarter of 2010 to $7.9 million for the current period due to lower salaries and consulting fees.

- Operating costs increased $4.6 million to $25.4 million ($1.93 per Mcfe) due to higher costs associated with Mannville oil production, increased power costs at Perpetual's gas storage facility related to the increased working gas capacity and workover charges related primarily to the gas storage wells.

- Net loss totaled $38.7 million for the three months ended December 31, 2011, as compared to $28.2 million for the fourth quarter of 2010. Lower funds flows in the current period were partially offset by reduced depletion and depreciation charges, unrealized gains on derivatives and gains on asset dispositions.

ANNUAL RESULTS

($ millions, except volumes and per Common Share amounts)	**2011**	2010	2009
Cash flow provided by operating activities	**60.4**	199.9	228.4
Cash flow provided by operating activities per Common Share (2)	**0.41**	1.42	1.93
Funds flow (1)	**77.0**	237.5	231.3
Funds flow per Common Share (1) (2)	**0.52**	1.69	1.96
Net earnings (loss)	**(95.9)**	(100.7)	14.4
Dividends	**28.9**	78.6	75.8
Dividends per Common Share (3)	**0.20**	0.56	0.64
Payout ratio (%) (1)	**37.3**	33.1	32.8
Exploration and development expenditures	**139.2**	115.2	57.4
Gas storage expenditures	**11.2**	57.6	10.8
Acquisitions, net of dispositions	**(33.4)**	50.9	103.9
Total capital expenditures	**117.0**	224.4	172.7
Net bank debt outstanding at December 31 (4)	**137.7**	214.5	270.8
Senior notes, measured at principal amount	**150.0**	-	-
Convertible debentures, measured at principal amount	**234.9**	234.9	230.2
Total net debt at December 31 (4)	**522.6**	449.4	501.0
Total net debt per Common Share (4) (6)	**3.56**	3.03	3.97
Daily average production (5)			
Natural gas (MMcf/d)	**130.2**	145.1	153.4
Oil & NGL (bbl/d)	**2,027**	1,245	721
Total (MMcfe/d)	**142.3**	152.6	157.7
Gas over bitumen deemed production	**26.4**	24.8	19.9
Total average daily (actual and deemed)	**168.7**	177.4	177.6
Production per Common Share – actual and deemed (cubic feet equivalent/d/Share) (2)	**1.14**	1.26	1.50

(1) These are non-GAAP measures; please refer to "Significant Accounting Policies and Non-GAAP measures" included in this MD&A.
(2) Based on weighted average Common Shares outstanding for the period.
(3) Based on Common Shares outstanding at each cash dividend date.
(4) Net debt is measured as at the end of the period and includes net working capital (deficiency) excluding short-term financial instrument assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, assets and liabilities held for sale and share option plan liabilities. Total net debt includes senior notes and convertible debentures, measured at the principal amount. Please refer to "Significant accounting policies and non-GAAP measures" included in this MD&A.
(5) Production amounts are based on company interest (working interest and royalties receivable) before royalties payable.
(6) Based on Common Shares outstanding at period end.

Capital expenditures

- Exploration and development capital spending increased to $139.2 million in 2011 from $115.2 million in 2010, as Perpetual acquired land and expanded capital activities on its Wilrich liquids-rich resource play in west central Alberta and increased exploration and development of conventional heavy oil in the Mannville area of eastern Alberta. In total 62 wells were drilled (60.5 net) with a 100 percent success rate, compared to 70 wells (63.9 net) in 2010.

- Evaluation drilling and coring expenditures were conducted on several of Perpetual's bitumen leases in northeast Alberta during 2011. The preliminary analysis of these reservoirs has been encouraging, and the Corporation has succeeded in obtaining contingent resource evaluations for the Liege, South Liege and Panny properties as a result of these initiatives.

- The Corporation disposed of non-core assets in the West Central and Northern districts for $41.7 million, providing additional liquidity while high-grading the Corporation's asset base. Acquisitions of $7.7 million were focused on adding to Perpetual's drilling inventory in Edson.

Financial

- Funds flow decreased 68 percent to $77.0 million in 2011 as compared to $237.5 million for 2010. The decrease was primarily due to a $151.5 million reduction in realized gains on derivatives from year to year. Excluding the effect of derivatives, funds flow decreased by $8.7 million due to lower natural gas production and pricing, partially offset by growing liquids production and gas storage revenues.

- On March 15, 2011 Perpetual issued $150 million of seven-year senior unsecured notes (the "Senior Notes"). The Senior Notes bear interest at 8.75 percent, payable semi-annually, and mature on March 15, 2018.

- Net loss for 2011 decreased five percent to $95.9 million, due to lower depletion and depreciation charges, partially offset by reduced funds flows compared to 2010.

- The Corporation declared dividends of $28.9 million or $0.195 per Common Share in 2011 as compared to $78.6 million or $0.56 per Common Share in 2010. On October 19, 2011 Perpetual announced that, given the continued weakness in natural gas prices, dividends would be suspended until further notice.

Production and reserves

- The Corporation's average gas price before derivatives decreased ten percent to $3.77 per Mcf in 2011 from $4.17 per Mcf in 2010, in line with an 11 percent decrease in AECO monthly index prices. Natural gas prices including derivatives declined to $3.82 per Mcf in 2011 from $7.10 in the prior year due to a $151.5 million reduction in realized gains on derivative contracts. Oil and NGL price before derivatives increased $5.61 per bbl to $73.90 per bbl for 2011 primarily as a result of higher reference prices. The increase in the Corporation's price is not as pronounced as the increase in posted prices due to the increasing percentage of heavy oil in Perpetual's oil and NGL production portfolio. The Corporation received $3.1 million in the fourth quarter of 2011 for the sale of a forward call option on 500 bbl/d of 2013 oil production, boosting the realized oil and NGL price to $78.06 per bbl for the current year.

- Daily average oil and NGL production increased by 782 bbl/d or 63 percent from 2010 levels, driven by successful heavy oil and liquids rich gas drilling during the year. Natural gas production decreased ten percent to 130.2 MMcf/d in 2011 as a result of non-core asset dispositions, the shut-in and sale of natural gas production at Liege in November 2010 due to gas over bitumen concerns and natural production declines, partially offset by high-impact drilling at Edson and low cost workover recompletion activities in the Eastern district to mitigate decline rates.

- In 2011, Perpetual added 61.1 Bcfe (10.2 MMboe) of proved and probable reserves, replacing 118 percent of its production (87 percent on a total proved basis). After dispositions of 12.2 Bcfe (2.0 MMboe) and production of 51.9 Bcfe (8.7 MMboe) in 2011, proved and probable reserves decreased less than one percent from 487.7 Bcfe (81.3 MMboe) at year-end 2010 to 484.7 Bcfe (80.8 MMboe) as at December 31, 2011.

- Including changes in future development capital ("FDC"), Perpetual realized finding and development costs ("F&D") of $2.86 per Mcfe ($17.16 per BOE) on a proved and probable reserve basis in 2011. Perpetual's realized finding, development and acquisition costs ("FD&A"), including changes in FDC, were $2.88 per Mcfe ($17.28 per BOE) on a proved and probable basis. Excluding 28.4 Bcf of downward reserve revisions related solely to natural gas price reductions, FD&A including changes in FDC was $1.82 per Mcfe ($10.92 per BOE) on a proved and probable basis.

OPERATIONS

Properties

In recent years Perpetual has initiated an asset base and commodity diversification strategy to add higher impact, growth oriented, resource-style opportunities to its asset portfolio, primarily in the deep basin of west central Alberta and also through exposure to shallow shale gas, heavy oil and bitumen opportunities in eastern Alberta.

Perpetual has made significant progress in this transition from its legacy asset base of conventional shallow natural gas assets in northeast and east central Alberta to add commodity and play diversification with conventional heavy oil and resource-style liquids rich gas and oil plays in the Alberta deep basin. In the fourth quarter of 2011, approximately 25 percent of production and 35 percent of the year-end reserve values came from Perpetual's resource-style assets in west central Alberta. Also in the fourth quarter, oil and NGL production volumes comprised 11 percent of total production volumes and through focused investment in two key priority plays, Wilrich and Mannville heavy oil, this is expected to grow to 15 to 20 percent of average production volumes in 2012.

Perpetual's producing assets are 100 percent concentrated in Alberta.

Eastern district

The Eastern district is geographically comprised of assets in northeast and east central Alberta. Perpetual's legacy gas producing assets acquired with its spin out from Paramount Resources Ltd. in 2003, complemented with consolidating and operationally synergistic asset acquisitions. Production in this multi-zoned potential area is from over ten different Cretaceous or Devonian aged reservoirs and consists of both conventional and tight unconventional shallow gas reservoirs. The northern part of this district largely overlaps the Athabasca Oil Sands area and the Corporation has also amassed a material inventory of oil sands leases for future development that will require a variety of subsurface recovery technologies.

The vast majority of Perpetual's shallow gas properties feature well established, high working interest production and most are operated by Perpetual. The base shallow gas production profile is predictable due to the lengthy production histories and the large number of independent producing entities in Perpetual's asset base. The large number of wells and facilities means unexpected downtime at any single site does not have a material impact on overall production.

Competitive operating costs and access to markets proximal to the producing properties combine to deliver relatively high field netbacks. Perpetual has an extensive inventory of low cost opportunities for value creation including workovers, uphole recompletions and an inventory of drilling prospects which extends throughout the shallow gas asset base. The Corporation has a history of adding production through relatively modest capital expenditures to offset most of the annual natural production declines. Strategic infrastructure ownership provides additional opportunities to add value through operating synergies and economies of scale.

Northeast – Northeast is comprised primarily of the original assets acquired from Paramount Resources at the inception of the Trust in 2003. Significant areas of production in this core area include Saleski, Woodenhouse, Craigend and Leismer. Production is primarily from the Devonian Grosmont and various overlying Cretaceous formations. The majority of the shut-in gas related to the gas over bitumen issue is in the Wabiskaw-McMurray formation in this area. Production was shut-in in 2003 and 2004 as a result of shut-in orders related to the gas over bitumen regulatory issue. Production at Legend was shut-in on October 31, 2009 as a result of an interim ERCB shut-in order related to a more recent gas over bitumen dispute with oil sands owners in the area. Additional production at Liege was shut in when both Legend and Liege were sold in 2010.

Athabasca – Athabasca includes assets south and west of the Corporation's original spin-out assets in the Northeast area. Production is from multiple stratigraphic horizons including Cretaceous clastic and Devonian carbonate reservoirs. Significant gas producing properties in this core operating area include Calling Lake, Darwin, Marten Hills, Panny, Peter Lake and Wabasca/Hoole.

Bitumen/Heavy Oil – Perpetual has over 336,000 net acres of bitumen rights within the northeast area of the Eastern district, including leases at Liege, Ells, Saleski, Panny, Hoole, Wabasca Lake, Calling Lake and Marten Hills. Certain reservoirs, particularly at Panny and Marten Hills, exhibit potential to achieve production through cold-flow technology whereas others will likely require intensive thermal recovery techniques to develop the bitumen resource. Perpetual has drilled evaluation wells at Panny, Liege and Hoole to further define the resource potential of its bitumen leaseholdings, and received independent contingent resource reports for all three areas in 2011.

Birchwavy East – Shallow gas production from the Birchwavy East area is primarily from Colony channel reservoirs in the Cretaceous Mannville zone as well as other conventional Mannville sand reservoirs. In addition, unconventional, tight, shallow gas resource play potential in the Viking and Colorado Group extend across these assets. The region has also become the focus of Perpetual's Mannville conventional heavy oil development program, with 29 wells drilled in 2011. The oil quality is consistent with Western Canadian Blend at Hardisty.

Birchwavy West - Warwick, Bruce and Killam areas of central Alberta are the major shallow gas producing properties in this core area. A significant inventory of proved and probable undeveloped reserves in the resource play in the Viking formation is booked in this area. As in Birchwavy East, this area holds significant potential for Viking and Colorado shale gas development in the future.

West Central district

The West Central district comprises a number of deep basin resource-style oil and liquids-rich gas plays developed as part of the Corporation's asset base transition initiated in 2008. Production is established from the Carrot Creek/Edson area and includes light crude oil and liquids-rich gas from the Belly River, Cardium, Second White Specks, Viking, Wilrich, Fahler, Ostracod, Ellerslie, Fernie sand, Rock Creek and Blueridge formations. Liquids-rich natural gas (20 to 40 bbl/MMcf) comes from both vertical wells with multiple commingled Cretaceous and Jurassic aged objectives, and horizontal wells with multi-stage fracture stimulations in the Wilrich, Fahler, Notikewin and Rock Creek formations. The West Central lands host a significant number of vertical multi-zone drilling opportunities as well as multiple years of high-impact horizontal drilling inventory to develop the Wilrich in the greater Edson area. The liquids production provides diversification of commodity price risk.

Elmworth Montney – Through grass roots exploration efforts and successful Crown lands sale purchases, Perpetual acquired material exposure to the Montney liquids-rich gas play developing at Elmworth in west central Alberta. To manage operational and technical risk, Perpetual entered into a joint venture arrangement with an industry partner whereby the partner would fund and operate three wells to evaluate the lands to earn a 50 percent working interest. The farm-in arrangement was completed in January 2011, and as a result Perpetual has a 50 percent interest in 78 sections of land with contingent resource and reserves established for Montney gas development. Several infrastructure options are being evaluated to bring the resource to production.

Warwick Gas Storage Inc. ("WGSI")

In late 2009, Perpetual initiated the development of a partially depleted gas reservoir within the Corporation's existing asset base near Vegreville, Alberta and in close proximity to Alberta gas transmission lines, for commercial gas storage purposes. The first test injection and withdrawal cycle was completed in March 2011. Working gas capacity for the second commercial storage cycle which commenced April 1, 2011 has been established at 17 Bcf.

Production

Production by core area and commodity	**2011**	2010	2009
Gas (MMcf/d)			
Eastern district	**102.5**	126.2	146.7
West Central district	**27.1**	18.2	5.6
Other	**0.5**	0.7	1.0
Total (MMcf/d)	**130.1**	145.1	153.4
Oil & NGL (bbl/d)			
Eastern district	**745**	256	405
West Central district	**1,280**	986	312
Other	**3**	3	4
Total (bbl/d)	**2,028**	1,245	721
Total (MMcfe/d)			
Eastern district	**107.0**	127.8	149.2
West Central district	**34.8**	24.1	7.5
Other	**0.5**	0.7	1.0
Total (MMcfe/d)	**142.3**	152.6	157.7
Deemed natural gas production (MMcf/d)	**26.4**	24.8	19.9
Total plus deemed production (MMcfe/d)	**168.7**	177.4	177.6

Natural gas production volumes decreased ten percent to 130.1 MMcf/d in 2011 from 145.1 MMcf/d in 2010, primarily due to the shut-in and sale of natural gas production at Liege in November 2010 and non-core property dispositions during the year. This was partially offset by the full-year effect of the Edson Acquisition completed on April 1, 2010, and subsequent successful drilling in the Wilrich formation at Edson and other high-impact liquids-rich gas prospects in the West Central district which contributed to production volumes in the fourth quarter of 2011. Current year capital programs targeted oil and NGL production additions, thereby allowing natural gas production to decline in favor of investment to bring higher priced oil and NGLs onstream.

The Liege production which was shut-in on November 17, 2010 was subject to an interim shut-in decision by the ERCB announced on May 10, 2011. Perpetual retained operatorship of the Liege assets in order to be eligible to receive the related gas over bitumen royalty adjustments once the decision was made, and began receiving these adjustments in respect of approximately 8.0 MMcf/d of deemed production on June 1, 2011 (see "Gas over bitumen royalty adjustments" in this MD&A).

Oil and NGL production volumes increased 783 bbl/d or 63 percent from 2010 levels. Capital spending for the year was concentrated on liquids-rich gas in the Edson area and continued successful development of several heavy oil pools at Mannville in eastern Alberta, which resulted in oil and NGL production exceeding 3,200 bbl/d for December 2011. Oil and NGL volumes were 8.6 percent of Perpetual's total production in 2011, as compared to 4.9 percent in 2010.

Total actual and deemed production decreased five percent to 168.7 MMcfe/d from 177.4 MMcfe/d in 2010, as lower natural gas production was partially offset by higher oil and NGL production and higher deemed natural gas production.

Capital expenditures

Capital expenditures ($ thousands)	**2011**	2010	2009
Exploration and development [1]	**122,761**	101,365	53,463
Crown and freehold land purchases	**16,453**	13,837	3,908
Gas storage	**11,207**	57,587	10,800
Acquisitions	**7,707**	142,210	130,465
Dispositions [2]	**(41,660)**	(91,252)	(26,580)
Other	**588**	707	649
Total capital expenditures	**117,056**	224,454	172,705

(1) Exploration and development expenditures for 2011 include approximately $3.9 million in exploration costs which have been expensed directly on the Corporation's statement of earnings (2010 - $4.0 million, 2009 - $6.4 million). Exploration costs including geological and geophysical expenditures and dry hole costs are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore they are included with capital expenditures.

(2) Dispositions for 2010 include the receipt of $7.1 million in common shares of Trioil Resources Ltd., a junior oil and gas company focused on the exploration and development of Cardium oil plays in southern Alberta, which were received as partial consideration for the sale of Perpetual's Cochrane property completed in the second quarter of 2010. Since this is a non-cash transaction, those proceeds are not included in the Corporation's statement of cash flows for 2010.

Exploration and development expenditures excluding land measured $122.8 million in 2011 as compared to $101.4 million for 2010. Capital spending was concentrated on exploration and development of liquids-rich natural gas in the West Central district, heavy oil drilling at Birchwavy East and evaluation of the Corporation's oil sands leases in northeast Alberta.

Land acquisitions totaled $16.5 million in 2011, a $2.6 million increase from 2010. Current year spending was directed primarily towards several exploratory parcels in the West Edson area of Alberta as well as expanding Perpetual's land position in Mannville and Elmworth.

West central

Perpetual drilled a total of ten wells (9.2 net) targeting the Wilrch formation at Edson, with an additional two wells (2.0 net) drilled subsequent to year-end. This drilling included a discovery well in the Wilrich at West Edson, doubling the inventory of prospective future locations. In the greater Edson area, Perpetual has now identified over 40 net horizontal drilling locations in the Wilrich formation for future development.

In addition, Perpetual successfully drilled and completed one vertical and one horizontal (2.0 net) development wells at Karr, targeting liquids-rich gas at 40 bbls per MMcf of NGLs. Both wells came on production in the second half of 2011.

Mannville heavy oil

In the Mannville area of east central Alberta, Perpetual continued to focus on exploration and development of cretaceous-aged conventional heavy oil pools geographically synergistic with the Corporation's shallow gas assets. Perpetual drilled a total of 29 (29.0 net) Mannville oil wells in 2011, increasing heavy oil production by over 1,000 percent during the year to 2,050 bbl/d for December 2011. Horizontal development of five Lloyd Formation pools and one Sparky pool was evaluated and development is ongoing at an initial horizontal well spacing of 200 metres. An additional ten horizontal development wells are planned for the first quarter of 2012. In addition, further exploratory drilling in the first quarter of 2012 will evaluate several other prospective pools for future development potential.

Bitumen

Perpetual holds over 41,400 hectares (162 net sections) of oil sands leases in the Panny Area of Northern Alberta. Throughout 2011, Perpetual has worked with its external reserves consultants McDaniel and Associates Ltd. ("McDaniel") to provide estimates of volumes of discovered bitumen initially in place ("DBIIP"), undiscovered bitumen initially in place ("UDBIIP"), contingent resources and prospective resources for a portion of the Corporation's assets in this area. Three vertical wells and a horizontal well were drilled in the area in the first quarter of 2011, and one existing well was deepened in the fourth quarter to evaluate the reservoir quality and bitumen characteristics of the Bluesky formation and to further define the extent of the bitumen resource and extraction potential. The assignments of DBIIP, UDBIIP, recoverable contingent resource and recoverable prospective resource in the McDaniel Report "Perpetual Energy Inc. Clastic Oil sands Resource Assessment Evaluation of Bitumen and Heavy Oil Resources as of June 30, 2011" and the subsequent update "Evaluation of Discovered Bitumen Initially-in-Place and Contingent Bitumen Resources – Panny Area" effective December 31, 2011 are based on approximately 59 wells in the pools, and on the potential application of cyclic steam stimulation to the Bluesky formation. These reports were prepared pursuant to National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities".

Given the extent of the bitumen resource now confirmed across the Panny acreage, the high quality of the Bluesky formation reservoir recovered in core, and that the viscosity of the bitumen discovered is capable of flowing at low rates without any thermal or solvent assistance, the Corporation is encouraged by the results to date at Panny. Perpetual has plans to further quantify the resource through additional drilling, has initiated a detailed review of applicable technologies, and has applied for a pilot test on its lands.

Perpetual holds over 41,000 hectares (161 net sections) of oil sands leases in the Hoole and Marten Hills Areas of Northern Alberta. Throughout 2011, the company has worked with McDaniel to provide estimates of volumes of UDBIIP, DBIIP, contingent resources and prospective resources for a portion of the Company's assets in these areas. Three vertical wells were drilled in the area and 13 km of 2D seismic were acquired in the first quarter of 2011, to evaluate the reservoir quality and bitumen characteristics of the Clearwater and Grand Rapids formations and to further define the extent of the bitumen resource and extraction potential. The assignments of DBIIP, UDBIIP, recoverable contingent resource and recoverable prospective resource in the McDaniel Report "Perpetual Energy Inc. Clastic Oil sands Resource Assessment Evaluation of Bitumen and Heavy Oil Resources as of June 30, 2011" are based on 57 wells in the pools, and on the potential application of cyclic steam stimulation to the Clearwater formation and Steam Assisted Gravity Drainage ("SAGD") to the Grand Rapids formation. The Report was prepared pursuant to National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities".

Perpetual holds 30,720 hectares (120 net sections) of oil sands leases in the Liege area. During the first quarter of 2011, the Company acquired 42 km of 2D seismic and drilled three wells which encountered bitumen-saturated reservoir in the Wabiskaw as well as in the Grosmont A, B and C and Leduc carbonate formations. Each of the three wells encountered three or more stacked zones, with at least one zone having greater than 10 meters of continuous bitumen-saturated reservoir. The assignments of DBIIP, UDBIIP, recoverable contingent resource and recoverable prospective resource in the McDaniel Report "Perpetual Energy Inc. Evaluation of Contingent and Prospective Resources of Grosmont and Leduc Bitumen As of October 31, 2011" are based on 55 wells in the pools and on the potential application of SAGD. The Report was prepared pursuant to National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities".

All of Perpetual's contingent resources currently have an "undetermined" economic status as sub-classification into economic and uneconomic categories has not been evaluated. Contingencies affecting the classification of the resources referred to in the McDaniel Reports referenced in the sections above as reserves include corporate development plans, the need for regulatory approval, and the need to perform an economic study regarding production. There is no certainty that it will be commercially viable to produce any portion of the resources. Please see "Notes Pertaining to the Reporting of Bitumen Contingent Resource" in this MD&A for applicable definitions and risk factors.

The bitumen in place and recoverable resource estimates, prepared in accordance with the COGE Handbook, are as follows:

Resource Category	Discovered[1] Gross Area (hectares)	Company WI	DBIIP (Mbbl)	Gross Recoverable Contingent Resource (Mbbl) [1]	Undiscovered[1] Gross Area (hectares)	Company WI	UDBIIP (Mbbl)	Gross Recoverable Prospective Resource (Mbbl) [1]
Panny Clastics								
Low Estimate[1]		100%	509,242	50,924				
Best Estimate[1]	5,184	100%	755,009	132,127				
High Estimate[1]		100%	983,040	245,760				
Other Clastics								
Low Estimate[1]		100%	36,467	5,470		100%	71,800	7,719
Best Estimate[1]	610	100%	70,691	14,178	676	100%	82,802	17,604
High Estimate[1]		100%	128,406	33,589		100%	167,274	46,737
Liege Carbonates								
Low Estimate[1]		100%	270,416	0		100%	1,629,912	0
Best Estimate[1]	2,717	100%	331,190	66,238	18,002	100%	1,996,227	399,245
High Estimate[1]		100%	405,623	162,250		100%	2,444,868	977,947
Total All Areas								
Low Estimate[1]		**100%**	**816,125**	**56,394**		**100%**	**1,701,712**	**7,719**
Best Estimate[1]	**8,511**	**100%**	**1,156,890**	**212,543**	**18,678**	**100%**	**2,079,029**	**416,849**
High Estimate[1]		**100%**	**1,517,069**	**441,599**		**100%**	**2,612,143**	**1,024,684**

(1) Contingent and prospective resources have been evaluated by McDaniel using the definitions is as defined in section five of the Canadian Oil and Gas Evaluators Handbook, Volume 1. All volumes are reported before the deduction of royalties payable to others. Contingent resource assignments are in addition to any reserve assignments associated with these assets. Please refer to the detailed definitions contained at the end of this release.

Warwick Gas Storage Inc.

Gas storage expenditures decreased to $11.2 million for 2011 from $57.6 million for the prior year. Prior year costs included construction of the storage facility, whereas 2011 expenditures were primarily directed to the drilling of three horizontal wells designed to increase the working gas capacity in the storage reservoir. Capacity was established at 17 Bcf for the second commercial storage cycle, which commenced April 1, 2011.

Acquisitions and dispositions

Acquisitions decreased from $142.2 million for the year ended December 31, 2010 to $7.7 million for the current period. Acquisitions in 2010 included the purchase of natural gas and liquids production as well as extensive gathering and processing infrastructure and undeveloped lands in a desirable multi-zone part of the Alberta deep basin (the “Edson Acquisition”). Current year acquisitions were focused on expanding the drilling inventory of Wilrich locations in the Edson area.

Dispositions for 2011 included non-core assets located in northeast and west central Alberta for net proceeds of $41.7 million, as compared to $91.3 million in 2010. Total gains on dispositions of property, plant and equipment decreased from $41.8 million in 2010 to $12.0 million for 2011 due to the lower number of dispositions in the current year.

Drilling

	2011		2010		2009	
Wells drilled	**Gross**	**Net**	Gross	Net	Gross	Net
Gas	**16**	**15.5**	48	44.3	46	36.2
Oil	**35**	**34.0**	14	11.6	2	2.0
Oilsands evaluation	**7**	**7.0**	-	-	-	-
Service	**1**	**1.0**	1	1.0	-	-
Gas storage	**3**	**3.0**	6	6.0	4	4.0
Dry	**-**	**-**	1	1.0	-	-
Total	**62**	**60.5**	70	63.9	52	42.2
Success rate (%)	**100**	**100**	99	98	100	100

Perpetual drilled 60.5 net wells in 2011 as compared to 63.9 wells in 2010. Oil and gas drilling activity in 2011 included:

- 29 (29.0 net) Mannville heavy oil wells (including one service well);
- Ten (9.2 net) wells targeting liquids-rich gas in the Wilrich formation at Edson;
- Five (4.8 net) wells in the West Central district to delineate other oil and liquids-rich gas plays;
- Three (3.0 net) wells targeting heavy oil cold-flow production at Panny;
- Five (4.5 net) strategic wells in the Eastern district to maintain land positions and add natural gas volumes at a low cost.

Reserves

Perpetual's complete National Instrument 51-101 ("NI 51-101") reserves disclosure as at December 31, 2011 including underlying assumptions regarding commodity prices, expenses and other factors, and reconciliation of reserves on a net interest basis (working interest less royalties payable) is contained in the Corporation's Annual Information Form for the year ended December 31, 2011.

The reserves data set out below (the "Reserves Data") is based upon an evaluation by McDaniel and Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2011 contained in a report of McDaniel dated February 6, 2012 (the "McDaniel Report"). The Reserves Data summarizes the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using McDaniel forecast prices and costs. The Reserves Data is presented on a company interest basis, including royalty interests and before royalty burdens. Columns and rows in reserve and net present value tables may not add due to rounding.

Oil and natural gas reserves as at December 31			**2011**			2010			2009
Proved	**Oil & NGL (Mbbl)**	**Gas (MMcf)**	**Total (MMcfe)**	Oil & NGL (Mbbl)	Gas (MMcf)	Total (MMcfe)	Oil & NGL (Mbbl)	Gas (MMcf)	Total (MMcfe)
Developed producing	**2,926**	**161,229**	**178,787**	2,360	187,223	201,380	1,786	192,033	202,757
Developed non-producing	**247**	**17,625**	**19,108**	141	20,786	21,633	81	7,808	8,293
Undeveloped	**1,449**	**28,467**	**37,155**	733	22,990	27,390	384	31,018	33,322
Total proved	**4,621**	**207,321**	**235,050**	3,234	230,999	250,402	2,251	230,859	244,372
Probable									
Producing, non-producing and undeveloped	**3,435**	**200,725**	**221,336**	2,017	198,030	210,133	1,129	174,626	181,398
Probable shut-in gas over bitumen	**-**	**28,319**	**28,319**	-	27,196	27,196	-	45,806	45,806
Total probable	**3,435**	**229,044**	**249,656**	2,017	225,226	237,329	1,129	220,432	227,204
Total proved & probable	**8,056**	**436,365**	**484,706**	5,252	456,224	487,731	3,380	451,291	471,576
Total proved & probable per Common Share (Mcfe/Share)			**3.30**			3.29			3.74

The proved producing reserves comprise 76 percent of the total proved reserves and 37 percent of the total proved and probable reserves, while proved and probable developed producing reserves are 51 percent of the total proved and probable reserves. Total proved reserves account for 48 percent of the total proved and probable reserves.

The Corporation's total proved & probable natural gas reserves at December 31, 2011 decreased four percent from 2010, as positive technical revisions due to improved production performance in the Eastern district and reserve additions from drilling activity at Edson were more than offset by natural gas production, property dispositions during the year and negative reserve revisions of 28.4 Bcfe due to economic limits, caused by a decrease in McDaniel forecast natural gas prices from year to year.

Proved and probable oil and NGL reserves increased by 53 percent over prior year levels due to the concentration of Perpetual's 2011 capital spending programs on heavy oil and liquids-rich gas development. Perpetual intends to continue to increase liquids reserves as a portion of the Corporation's asset portfolio in 2012 with development capital directed primarily to these assets.

McDaniel's price forecast utilized in the evaluation is summarized below.

McDaniel January 1, 2012 price forecast

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/MMBtu)	Foreign Exchange ($US/$Cdn)
2012	97.50	99.00	3.50	0.975
2013	97.50	99.00	4.20	0.975
2014	100.00	101.50	4.70	0.975
2015	100.80	102.30	5.10	0.975
2016	101.70	103.20	5.55	0.975
2017	102.70	104.20	5.90	0.975
2018	103.60	105.10	6.25	0.975
2019	104.50	106.00	6.45	0.975
2020	105.40	106.90	6.70	0.975
2021	107.60	109.20	6.85	0.975
2022	109.70	111.30	6.95	0.975
2023	111.90	113.50	7.05	0.975
2024	114.10	115.80	7.20	0.975
2025	116.40	118.10	7.40	0.975
Escalate thereafter at	2%	2%	2%	0.975

Perpetual's proved and probable reserves to production ratio at December 31, 2011, also referred to as reserve life index ("RLI") was 9.7 years while the proved RLI was 5.3 years, based on 2012 production estimates in the McDaniel Report. These represent increases of 11 percent and eight percent, respectively from the RLI at December 31, 2010.

The net present values of future net revenues ("NPV") for Perpetual's reserves, before taxes using McDaniel forecast prices and costs at zero, five and ten percent discount rates are presented in the table below.

NPV of reserves at December 31			**2011**			2010			2009
($ millions)	**0%**	**5%**	**10%**	0%	5%	10%	0%	5%	10%
Proved									
Developed producing	**482.2**	**393.0**	**335.8**	674.3	537.7	453.4	784.3	654.6	569.5
Developed non-producing	**79.6**	**37.8**	**24.0**	99.7	44.4	26.4	17.6	14.0	11.9
Gas over bitumen royalty adjustments	**65.1**	**54.8**	**47.1**	110.6	92.3	78.8	129.9	109.9	94.9
Undeveloped	**77.2**	**42.4**	**24.8**	57.2	36.0	23.2	77.2	56.0	41.1
Total proved	**704.1**	**528.0**	**431.6**	941.8	710.4	581.8	1,009.0	834.5	717.4
Probable									
Developed and undeveloped	**547.5**	**341.2**	**240.6**	652.6	417.0	293.4	727.2	497.4	359.9
Shut-in gas over bitumen reserves (1)	**92.1**	**66.9**	**50.2**	105.9	73.6	53.0	100.3	55.3	32.3
Total probable	**639.6**	**408.1**	**290.8**	758.5	490.6	346.4	827.5	552.7	392.2
Total proved & probable	**1,343.7**	**936.1**	**722.4**	1,700.3	1,201.0	928.2	1,836.5	1,387.2	1,109.6
Common Shares outstanding (millions)	**147.0**	**147.0**	**147.0**	148.3	148.3	148.3	126.2	126.2	126.2
Total proved & probable per Common Share ($/Share)	**9.14**	**6.37**	**4.91**	11.47	8.10	6.26	14.55	10.99	8.79

(1) The McDaniel Report assumes that the shut-in gas over bitumen reserves are probable but the future abandonment and reclamation liability associated with the wells is proved, that the reserves return to production after ten years of shut-in and that such production is subject to an incremental ten percent gross overriding royalty payable to the Crown.

At a ten percent discount factor, the proved producing reserves comprise 46 percent of the total proved and probable value while proved and probable developed producing reserves represent 69 percent of the total proved and probable value. Total proved reserves account for 60 percent of the proved and probable value.

After-tax reserve amounts from the McDaniel Report using forecast prices and costs are shown below.

After-tax net present values as at December 31, 2011 ($ millions, discounted at 0% and 10%)	**Total proved** **0%**	**10%**	**Total proved and probable** **0%**	**10%**
Net present value, before taxes	704.1	431.6	1,343.7	722.4
Income taxes	-	-	(133.1)	(50.5)
Net present value, after taxes	**704.1**	**431.6**	**1,210.6**	**671.9**

The McDaniel Report assumes the utilization of Perpetual's current existing tax pools plus additions from future development costs for proved and probable reserves, beginning in 2012 with taxation of after-tax cash flow at corporate income tax rates beginning in 2016. The Corporation has tax pools in excess of the undiscounted value of its proved reserves, and therefore income taxes paid on the production and sale of proved reserves are estimated to be zero.

The following table sets forth a reconciliation of the changes in reserves for the year ended December 31, 2011 from the opening balance on December 31, 2010 derived from the the McDaniel Reports at those dates, using McDaniel forecast prices.

Reserves reconciliation (MMcfe)	Proved	Probable	Proved & Probable
December 31, 2010	250,402	237,329	487,731
Discoveries and extensions	43,247	34,966	78,213
Technical revisions	21,632	(10,323)	11,309
Acquisitions, net of dispositions	(8,387)	(3,829)	(12,216)
Production	(51,939)	-	(51,939)
Economic factors	(19,905)	(8,487)	(28,392)
December 31, 2011	**235,050**	**249,656**	**484,706**

Finding and development ("F&D") costs

Under NI 51-101, the methodology to be used to calculate F&D and FD&A costs includes incorporating changes in FDC required to bring the proved undeveloped and probable reserves to production. For continuity, Perpetual has presented herein F&D and FD&A costs calculated both excluding and including FDC. Changes in forecast FDC occur annually as a result of development activities, acquisitions and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production. McDaniel estimated the FDC required to convert proved and probable non-producing and undeveloped reserves to producing reserves at $317.6 million, an increase of $35.4 million from McDaniel's estimate of FDC at December 31, 2010. The increase is primarily due to costs related to additional non-producing reserves booked at Edson, Mannville and Elmworth during the year.

The following table summarizes Perpetual's F&D and FD&A costs, before and after the inclusion of changes in FDC. Finding and development costs, including changes in FDC were $2.86 per Mcfe ($17.16 per BOE) on a proved and probable basis in 2011.

Perpetual has also summarized in the table below these same metrics with the effect of the price-related reserve revisions removed. Perpetual believes that the majority of these reserves will return to the books with a recovery in natural gas prices as the technical merits for booking the reserves have not changed, only the economic circumstances. Excluding the effects of negative reserve revisions related to substantially lower forward gas prices, including changes in FDC, Perpetual's F&D costs were $1.95 per Mcfe ($11.70 per BOE) for proved and probable reserves and FD&A costs were $1.82 per Mcfe ($10.92 per BOE) in 2011 on a proved and probable basis.

2011 F&A and FD&A costs – company interest reserves

($millions, except as noted)	Proved	Proved Excluding Price Revisions(2)	Proved & Probable	Proved and Probable Excluding Price Revisions(3)
F&D Costs, Excluding FDC				
Exploration and Development Capital Expenditures(1)	$139.2	$139.2	$139.2	$139.2
Reserve Additions Including Revisions – Bcfe	45.0	64.9	61.1	89.5
F&D – $/Mcfe(4)	**$3.09**	**$2.14**	**$2.28**	**$1.56**
F&D Costs, Including FDC				
Exploration and Development Capital Expenditures	$139.2	$139.2	$139.2	$139.2
Total Change in FDC	40.4	40.4	35.4	35.4
Total F&D Capital including Change in FDC	$179.6	$179.6	$174.6	$174.6
Reserve Additions Including Revisions – Bcfe	45.0	64.9	61.1	89.5
F&D Costs– $/Mcfe(4)	**$3.99**	**$2.77**	**$2.86**	**$1.95**
FD&A Costs, Excluding FDC				
Exploration and Development Capital Expenditures	$139.2	$139.2	$139.2	$139.2
Net acquisitions	(34.0)	(34.0)	(34.0)	(34.0)
FD&A Capital Expenditures Including Net Acquisitions	$105.2	$105.2	$105.2	$105.2
Reserve Additions Including Net Acquisitions – Bcfe	36.6	56.5	48.9	77.3
FD&A Costs – $/Mcfe(4)	**$2.87**	**$1.86**	**$2.15**	**$1.36**
FD&A Costs, Including FDC				
FD&A Capital Expenditures Including Net Acquisitions	$105.2	$105.2	$105.2	$105.2
Total Change in FDC	40.4	40.4	35.4	35.4
Total FD&A Capital Including Change in FDC	$145.6	$145.6	$140.6	$140.6
Reserve Additions Including Net Acquisitions – Bcfe	36.6	56.5	48.9	77.3
FD&A Costs Including FDC – $/Mcfe(4)	**$3.98**	**$2.58**	**$2.88**	**$1.82**

(1) $11.1 million of capital associated with WGSI has been excluded, includes $16.5 million of undeveloped land capital.
(2) 19.9 Bcf of proved reserves associated with price related revisions have been added back into the total reserve additions and revisions.
(3) 28.4 Bcf of proved and probable reserves associated with price related revisions have been added back into the total reserve additions and revisions.
(4) The aggregate of exploration and development costs incurred in the most recent financial year and the change in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Land

	2011		2010		2009	
Land inventory	**Net acres**	**Average working interest (%)**	Net acres	Average working interest (%)	Net acres	Average working interest (%)
Developed	**1,464,407**	**67.39**	1,516,366	67.49	1,666,352	68.0
Undeveloped	**1,849,013**	**83.46**	1,905,009	84.09	2,092,637	83.1
Total	**3,313,420**	**75.50**	3,421,375	75.82	3,758,989	75.6

Perpetual's undeveloped net acreage position decreased three percent from 2010 levels due to lease expiries and disposed acreage, partially offset by land purchases in west central Alberta and Mannville. Perpetual has an extensive inventory of undeveloped land relative to its production and reserves base.

The Corporation's undeveloped acreage in the Northeast core area includes approximately 239,000 net acres inside the gas over bitumen area of concern. While development of this acreage is restricted in certain formations, there are numerous other prospective zones in the region. The mineral rights for leases with shut-in production are continued indefinitely under Section 8(1)(h) of the *Mines and Minerals Act* (Alberta) until resolution of the gas over bitumen issue. Further, Perpetual has in inventory a total of 334,000 net acres of undeveloped oil sands leases.

Perpetual's third party estimate of the fair market value of its undeveloped acreage by region for purposes of the above net asset value calculation is based on recent Crown land sale activity adjusted for tenure and other considerations and is as follows.

Fair value of undeveloped land

Area	Acres	Total value ($thousands)	$/Acre
North	903,786	34,663	38.35
South	446,867	44,711	100.06
West central	143,751	56,184	390.84
New ventures	20,230	1,921	94.96
Oil sands	334,379	50,770	151.83
Total	**1,849,013**	**188,249**	**101.81**

The eight percent decrease in estimated fair value of undeveloped land to $188 million at December 31, 2011 from $204 million at December 31, 2010 is primarily due to the sale of Cardium acreage during the year and a reduction in the fair value of Perpetual's fee simple acreage in central Alberta, partially offset by an increase in value of the Corporation's oilsands leases.

Net asset value

The following net asset value ("NAV") table shows what is normally referred to as a "produce-out" NAV calculation under which the Corporation's reserves would be produced at McDaniel's forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of Perpetual common shares. Actual results will differ materially from the assumptions mandated by NI 51-101, as these do not reflect the full potential value of the Corporation's extensive prospect inventory.

The value of the WGSI facility has been recorded at cost in the net asset value calculation below. Construction of the WGSI facility was completed in the fourth quarter of 2010.

Pre-tax net asset value at December 31, 2011				**Discounted at**
($millions except as noted)	**Undiscounted**	**5%**	**8%**	**10%**
Total proved and probable reserves [1]	1,344	936	795	722
Fair market value of undeveloped land [2]	188	188	188	188
Market value of TriOil Resources Ltd. shares	4	4	4	4
Warwick gas storage [3]	85	85	85	85
Net bank debt [4]	(142)	(142)	(142)	(142)
Convertible debentures	(235)	(235)	(235)	(235)
Senior notes	(150)	(150)	(150)	(150)
Estimate of additional future abandonment and reclamation costs [5]	(121)	(69)	(52)	(43)
Mark to McDaniel's cost of WGSI forward sale obligation [6]	(42)	(35)	(31)	(29)
Net asset value	**932**	**583**	**463**	**401**
Common Shares outstanding (million) - basic	147	147	147	147
Net asset value per Share ($/Common Share)	**6.34**	**3.96**	**3.15**	**2.73**

(1) Reserve values per McDaniel Report as at December 31, 2011.
(2) Third party estimate.
(3) Book value recorded at cost as at December 31, 2011.
(4) Includes bank debt, net of working capital excluding marketable securities, derivative assets and liabilities and share based payment liability
(5) Amounts are net of salvage value and in addition to amounts in the McDaniel Report for future well abandonment costs related to developed reserves. See "Abandonment and reclamation costs".
(6) Value of Perpetual's forward sale obligation related to the gas storage funding arrangement at December 31, 2011 assuming settlement against the McDaniel price forecast.

The above evaluation includes future capital expenditure expectations required to bring undeveloped reserves recognized by McDaniel and GLJ that meet the criteria for booking under NI 51-101 on production. In order to independently assess the "going concern" value of the Corporation, a more detailed independent assessment would be required of the upside potential of specific properties and the ability of the Perpetual team to continue to make value-adding capital expenditures, some of which may require external financing.

Perpetual's three year history of net asset value and net asset value per Common Share, discounted at eight percent and including dividends paid to Shareholders, is as follows.

Pre-tax net asset value at December 31, discounted at 8%

($ millions except per share amounts)	2011	2010	2009
Net asset value	**463**	775	830
Net asset value per Common Share ($/Share)	**3.15**	5.23	6.59
Dividends per Common Share ($/Share)	**0.20**	0.56	0.64
Net asset value per Common Share including dividends paid ($/Share)	**3.35**	5.79	7.23

MARKETING

Natural gas prices

Natural gas price ($/Mcf, except percentages)	2011	2010	2009
Reference prices			
AECO Monthly Index	**3.67**	4.13	4.14
AECO Daily Index	**3.63**	4.00	3.98
Alberta Gas Reference Price (1)	**3.46**	3.77	3.85
Average Perpetual prices			
Before derivatives (2)	**3.77**	4.17	4.12
Percent of AECO Monthly Index	**103**	101	100
Including derivatives ("realized" natural gas price)	**3.82**	7.10	7.09
Percent of AECO Monthly Index	**104**	172	171

(1) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.

(2) Natural gas price before derivatives includes physical forward sales contracts for which delivery was made during the reporting period but excludes realized gains and losses on financial derivatives.

U.S. natural gas prices are typically referenced to NYMEX at the Henry Hub in Louisiana, while western Canada natural gas prices are referenced to the AECO Hub in Alberta. AECO Monthly Index prices decreased 11 percent from 2010 to 2011, averaging $3.67 per Mcf for the current year. North American natural gas prices have been under downward pressure since 2008 as a result of increased supply from shale gas plays coupled with reduced industrial demand. A lack of weather-related demand in late 2011 continued to push AECO prices downward, resulting in a December AECO monthly index price of $3.05 per Mcf. Perpetual's natural gas price before financial hedging decreased ten percent to $3.77 per Mcf in 2011 from $4.17 per Mcf in 2010, commensurate with the decline in AECO prices. The Corporation's natural gas price exceeds the AECO Monthly Index price due to the inclusion of a physical fixed-price contract for 10,000 GJ/d at a price of $7.75 per GJ in natural gas revenues for January to March 2011.

Perpetual's average realized gas price was $3.82 per Mcf in 2011 compared to $7.10 per Mcf in 2010. Realized gas prices were well above the AECO Monthly Index for 2010 due to realized gains on derivatives of $155.0 million.

Oil and NGL prices

Oil and NGL prices ($/bbl)	2011	2010	2009
West Texas Intermediate ("WTI") light oil (US$/bbl)	**94.01**	79.53	61.80
Average Perpetual prices			
Before derivatives	**79.16**	68.29	61.91
Including derivatives ("realized" oil and NGL price)	**91.63**	68.29	61.91

The Corporation's oil and NGL price increased to $79.16 per bbl in 2011 from $68.29 per bbl in 2010, primarily due to higher reference oil prices, partially offset by an increasing proportion of heavy oil production included in Perpetual's liquids production mix. Perpetual's realized price increased to $91.63 per bbl due to the receipt of $3.1 million in 2011 for the sale of a call option on 500 bbl/d of oil at US$105 per bbl for calendar year 2013, measured against the WTI index. Consistent with prior years, cash received for call options sold is included in realized prices and cash flow from operating activities, as well as funds flow.

Risk management

Perpetual's commodity price risk management strategy is focused on using derivative instruments to mitigate the effect of commodity price volatility on funds flow, to lock in attractive economics on capital programs and acquisitions and to take advantage of perceived anomalies in commodity markets. The Corporation uses both financial arrangements and physical forward sales to economically hedge up to a maximum of 60 percent of the trailing quarter's production including gas over bitumen deemed volumes in accordance with the limits under the Corporation's credit facility and Hedging and Risk Management Policy. Perpetual will also enter into foreign exchange swaps and physical or financial swaps related to the differential between natural gas prices at the AECO and NYMEX trading hubs in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's realized prices. The term "derivatives" includes all financial and physical risk management contracts. Although Perpetual considers the majority of these risk management contracts to be effective economic hedges against potential commodity price volatility, the Corporation does not follow hedge accounting for its derivatives.

Perpetual's risk management activities are conducted by an internal Risk Management Committee under guidelines approved by the Corporation's Board of Directors. Perpetual's risk management strategy, though designed primarily to protect funds flow, capital programs and debt management, is opportunistic in nature. Depending on management's perceived position in the commodity price cycle the Corporation may elect to reduce or increase its risk management position within the approved guidelines. The Corporation mitigates credit risk by entering into derivative contracts with financially sound, credit-worthy counterparties.

For a complete list of Perpetual's outstanding derivatives as at December 31, 2011, please see note 17 to the annual consolidated financial statements as at and for the year ended December 31, 2011. Financial and physical forward natural gas sales arrangements at the AECO trading hub as at March 7, 2012 are as follows:

Type of contract	**Term**	**Volumes at AECO (GJ/d)(1)**	**Price ($/GJ)(1)**	**Futures market ($/GJ)(4)**	**% of 2012 gas production(2)**
Financial – AECO (3)	January - December 2012	45,250	3.72	2.09	35
Financial - NYMEX	March 2012	50,000	2.52	2.45	3
Financial - AECO	March 2012	40,000	2.20	1.97	3
Financial - AECO	April - October 2012	10,000	2.85	1.84	4
Financial - AECO	April - December 2012	19,000	2.60	1.99	11
Physical - AECO	April - December 2012	25,000	2.59	1.99	14
Financial - AECO	January - December 2013	25,000	3.23	2.82	19

(1) Average price calculated using weighted average price for net open sell contracts. NYMEX prices in $US/MMBtu.
(2) Calculated using 2012 estimated gas production of 130,000 GJ/d including gas over bitumen deemed production.
(3) These derivative transactions are part of paired transactions in which the proceeds from the sale of crude oil call options which were used to fund the 2012 natural gas contracts at the price indicated.
(4) Futures market price incorporates settled AECO Monthly Index and NYMEX prices for January to March 2013 and forward AECO prices as of March 7, 2012.

Perpetual also has in place the following costless collar oil sales arrangements, to reduce exposure to fluctuations in the WTI index:

Type of contract	**Term**	**Volumes at WTI (bbl/d)**	**Floor price ($US/bbl)(1)**	**Ceiling price ($US/bbl)(1)**	**Futures market ($US/bbl)(3)**	**% of 2012 oil production(2)**
Collar	January – December 2012	500	82.00	91.00		14
Collar	January - December 2012	500	80.00	89.00		14
Collar	January - December 2012	500	85.00	97.00		14
Collar	January – December 2012	500	90.00	109.25		14
Period total	January - December 2012	2,000	84.25	96.50	106.46	56

(1) Average price calculated using weighted average price for net open contracts.
(2) Calculated using 2012 estimated oil and NGL production of 3,600 bbl/d.
(3) Futures market price incorporates settled and forward WTI oil prices as of March 7, 2012

The Corporation has entered into two contracts to fix the WTI to oil price differential (WCS differential) on 400 bbl/d at $US17.35 per bbl and on 500 bbl/d at US$28.75 per bbl, both for the 2012 calendar year.

In addition, the Corporation has sold oil call options exercisable and expiring as follows. A premium of $3.1 million was received in the fourth quarter of 2011 for the 2013 call option priced at $105 per bbl, which was included in funds flows for the period.

Type of contract	**Term**	**Expiry**	**Volumes at WTI (bbl/d)**	**Strike price ($US WTI)**	**Futures market ($US WTI)**
Call	January - December 2013	Dec 31, 2012	1,000	95.00	105.55
Call	January - December 2013	monthly	1,000	105.00	105.55
Call	January - December 2014	monthly	2,000	105.00	99.65

Perpetual has entered into the following U.S. dollar forward sales arrangements to limit the Corporation's exposure to the effects of strength in the Canadian dollar on natural gas prices.

Type of contract	Term	Perpetual sold/bought	Notional $USD/month	Exchange rate ($CAD/$USD)
Financial	January – December 2012	bought	($1,000,000)	$1.0019
Financial	January – December 2012	bought	($1,000,000)	$1.0085
Financial	January – December 2012	bought	($1,000,000)	$1.0125
Financial	January – December 2012	bought	($2,000,000)	$1.0535

Perpetual entered into forward financial power contracts to mitigate the risk to operating costs associated with fluctuations in power prices at the WGSI facility. Contracts outstanding at March 7, 2012 are as follows:

Type of contract	Term	Perpetual sold/bought	Volume (MWh)	Price ($CAD/MWh)
Financial	January 2012	bought	(7,261.44)	$ 63.77
Financial	February 2012	bought	(5,950.80)	$ 64.13
Financial	March 2012	bought	(5,133.60)	$ 62.58
Financial	January – March 2013	bought	(6,480.00)	$ 76.00

FINANCIAL RESULTS

Revenue

Revenue ($ thousands)	2011	2010	2009
Natural gas revenue [(1)]	**179,110**	221,099	229,943
Oil and NGL revenue	**54,674**	31,036	16,300
Gas storage revenue	**14,025**	8,082	-
Realized gains on derivatives [(2)]	**2,217**	155,025	166,340
Call option premiums received	**3,123**	1,851	5,740
Total revenue	**253,149**	417,093	418,323

(1) Includes revenues related to physical forward sales contracts which settled during the period.
(2) Realized gains on derivatives include settled financial forward contracts and options.

Natural gas revenue decreased to $179.1 million in 2011 from $221.1 million in 2010 due to lower gas prices and a ten percent decrease in production volumes, while oil and NGL revenues increased by $23.6 million as a result of higher production and pricing compared to the prior year. Realized gains on derivatives totaled $2.2 million in 2011 as compared to $155.0 million for 2010. Perpetual had anticipated a low gas price environment in 2011 and crystallized $37.3 million in gains on derivatives in the fourth quarter of 2010 related to 2011 financial natural gas contracts, in order to pre-fund the majority of capital spending programs for the first quarter of 2011, leading to the lower realized gains in the current year.

Gas storage revenue is derived from injecting, storing and withdrawing natural gas from the WGSI facility on behalf of third parties, and is recorded in accordance with the terms of the storage contracts. Storage revenue increased to $14.0 million for 2011 from $8.1 million for 2010 as withdrawals were not initiated until January 2011. The capacity of the facility was increased to 17 Bcf for the second storage cycle which commenced on April 1, 2011.

The Corporation also recorded unrealized losses on derivatives of $9.4 million in 2011, reflecting the change in the fair value of financial and physical forward commodity contracts during the year.

Funds flow

Funds flow reconciliation	**2011** $ millions	**2011** ($/Mcfe)	2010 $ millions	2010 ($/Mcfe)	2009 $ millions	2009 ($/Mcfe)
Production volume (Bcfe)	**52.0**		55.7		57.5	
Revenue [(1)]	**253.1**	**4.87**	417.1	7.49	418.3	7.27
Royalties	**(20.6)**	**(0.40)**	(22.1)	(0.40)	(17.4)	(0.30)
Operating costs [(2)]	**(89.3)**	**(1.72)**	(91.2)	(1.64)	(105.1)	(1.83)
Transportation costs	**(10.3)**	**(0.20)**	(11.9)	(0.21)	(11.7)	(0.20)
Operating netback from production	**132.9**	**2.55**	291.9	5.24	284.1	4.94
Gas over bitumen royalty adjustments	**11.5**	**0.22**	12.3	0.22	10.4	0.18
Exploration and evaluation [(3)]	**(3.9)**	**(0.07)**	(4.4)	(0.08)	(4.2)	(0.07)
General and administrative [(3)]	**(30.1)**	**(0.58)**	(34.4)	(0.62)	(32.1)	(0.56)
Interest on debt	**(6.6)**	**(0.13)**	(11.9)	(0.21)	(11.9)	(0.21)
Interest on senior notes [(3)]	**(10.5)**	**(0.20)**	-	-	-	-
Interest on convertible debentures [(3)]	**(16.3)**	**(0.31)**	(16.3)	(0.29)	(15.0)	(0.26)
Funds flow [(3) (4)]	**77.0**	**1.48**	237.5	4.26	231.3	4.02

(1) Revenue includes realized gains and losses on derivatives, call option premiums received and gas storage revenue.
(2) Operating costs included $5.0 million ($0.10 per Mcfe) related to the operation of the WGSI Facility.
(3) Excludes non-cash items.
(4) This is a non-GAAP measure; see "Other non-GAAP measures" in this MD&A.

Royalties

Perpetual pays Crown, freehold and gross overriding royalties which are dependent upon production volumes, commodity prices, location and age of producing wells and type of production. Gas Crown royalties are reduced by Gas Cost Allowance ("GCA") deductions, which are based on processing fees and allowable capital costs incurred at a property and are in accordance with Crown royalty regulations. Crown royalty rates tend to decrease with decreases in the Alberta Gas Reference Price, and rise as the reference price increases. Oil royalties are taken in kind directly from the wellhead by the Alberta Crown, and an amount is calculated based on the oil price received by the Corporation and included in royalties expense.

The average royalty rate on oil, NGL and natural gas revenues before derivatives was consistent at 8.8 percent for both 2010 and 2011. Higher natural gas royalties caused by lower gas cost allowance credits were offset by lower oil royalties, as the majority of Perpetual's oil production in 2011 is from new drills that qualify for a five percent royalty for the first year of production.

Operating costs

Operating costs	**2011** $ thousands	**2011** ($/Mcfe)	2010 $ thousands	2010 ($/Mcfe)
Production-related operating costs	**84,328**	**1.62**	89,702	1.61
WGSI operating costs	**4,994**	**0.10**	1,459	0.03
Total operating costs	**89,322**	**1.72**	91,161	1.64

Operating costs include all costs associated with the production of oil and natural gas from the wellhead to the point at which the product enters a sales pipeline for transport to market. Field gathering and processing costs are also included in operating costs. Revenue received from the processing of third party production at Perpetual's facilities is netted against operating costs.

Production-related operating costs decreased six percent to $84.3 million ($1.62 per Mcfe) in 2010 as compared to $89.7 million ($1.61 per Mcfe) in 2010, primarily due to lower production levels partially offset by higher workover charges. WGSI operating costs increased in 2011 as it was the first full year of operations for the WGSI facility. Gas injection first commenced on May 1, 2010. The largest component of WGSI operating costs is power charges, primarily required over the winter months when gas is being withdrawn, and as such Perpetual has entered into fixed-price power purchase contracts to manage these costs. Over the past few years Perpetual has implemented cost reduction initiatives at all operated fields to enhance competitiveness and efficiency.

Transportation costs

Costs to transport gas from the plant gate to the commercial market sales point are not reflected as an operating cost but rather are separately recorded as transportation costs for the product. Alberta's gas transportation system operates on a postage stamp basis. Total transportation costs decreased to $10.3 million in 2011 from $11.9 million in 2010, consistent with the decrease in natural gas production levels from year to year. On a unit-of-production basis, transportation costs decreased to $0.20 per Mcfe compared to $0.21 per Mcfe in 2010.

Operating netbacks

Perpetual's operating netback decreased by $159.0 million to $132.9 million for the year ended December 31, 2011 from $291.9 million for the prior year, due primarily to lower realized gains on derivatives, reduced gas production and gas prices, partially offset by increasing oil production and gas storage revenues.

Operating netback reconciliation ($ millions)	
Natural gas price decrease before derivatives	(21.4)
Natural gas production decrease	(20.6)
Oil and NGL price increase before derivatives	2.6
Oil and NGL production increase	21.1
Decrease in gains on derivatives	(151.5)
Gas storage revenue increase	5.9
Royalty expense decrease	1.5
Operating cost decrease	1.8
Transportation cost decrease	1.6
Decrease in operating netback	(159.0)

Gas over bitumen royalty adjustments

In 2004 and 2005 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas ("Royalty Regulation"), which provide a mechanism whereby the Government may prescribe additional royalty components to effect a reduction in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB, or its successor the ERCB as a result of certain bitumen conservation decisions. The formula for calculation of the royalty reduction provided in the Royalty Regulation is:

0.5 x ((deemed production volume x 0.80) x (Alberta Gas Reference Price - $0.3791/GJ))

Through this formula, operating costs are effectively deemed to be $0.40 per Mcf, royalties are deemed to be 20 percent, the deemed production is assigned the Alberta Gas Reference Price, which includes a transportation component and the entire formula is assigned a 50 percent reduction factor. The deemed production volumes is reduced by ten percent annually. The components of netbacks for the gas over bitumen shut-in reserves are outlined below.

Gas over bitumen royalty adjustment netback ($ per Mcf)	**2011**	2010	2009
Average deemed volume (MMcf/d)	**26.4**	24.8	19.9
Gas price	**3.46**	3.77	3.85
Royalties	**(0.70)**	(0.75)	(0.77)
Operating costs	**(0.40)**	(0.40)	(0.40)
50% reduction factor	**(1.18)**	(1.31)	(1.34)
Gas over bitumen royalty adjustment netback	**1.18**	1.31	1.34

The Corporation's net deemed production volume for purposes of the royalty adjustment was 26.4 MMcf/d for 2011. Deemed production represents all Perpetual natural gas production shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the AEUB or ERCB, or through correspondence in relation to an AEUB ID 99-1 application. In accordance with IL 2004-36, the deemed production volume related to wells shut-in is reduced by ten percent per year on the anniversary date of the shut-in order. Deemed production increased by 1.6 MMcf/d from the 24.8 MMcf/d recorded for 2010 as a result of royalty adjustments for the shut in volumes at Liege, which the Corporation began receiving in June 2011, partially offset by the annual ten percent reduction in deemed production volumes discussed previously.

A significant portion of royalty adjustments received have been recorded on Perpetual's statement of financial position rather than reported as income as the Corporation cannot determine if, when or to what extent the royalty adjustments may be repayable through incremental royalties if and when gas production recommences. Royalty adjustments may be repayable to the Crown in the form of an overriding royalty on gas production from wells which resume production within the gas over bitumen area. However, all royalty adjustments are recorded as a component of funds flow.

Perpetual has disposed of certain shut-in gas wells in the gas over bitumen area. As part of the disposition agreements, the Corporation continues to receive the gas over bitumen royalty adjustments related to the sold wells, although the ownership of the natural gas reserves is transferred to the buyer. As such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer Perpetual's responsibility. As a result of these dispositions, the gas over bitumen royalty adjustments received by the Corporation for the affected wells are considered revenue since they will not be repaid to the Crown.

Gas over bitumen royalty adjustments are not paid to Perpetual in cash, but are a deduction from the Corporation's monthly natural gas royalty invoices. In periods of low gas prices the Corporation's net Crown royalty expenses were too low to recover the full amount of the gas over bitumen royalty adjustments, and as such royalty adjustments for past periods will be recovered in future periods. All royalty adjustments, whether or not they have been recovered, have been included in funds flow in the periods in which they appeared on the natural gas royalty invoices. Eventual realization of the royalty adjustments is highly likely as deemed production is reduced by ten percent annually, whereas the Corporation is focused on maintaining production and reserves year over year through capital spending programs, complemented with strategic acquisitions. As of December 31, 2011, the Corporation has accumulated $9.0 million (December 31, 2010 – $8.5 million) of gas over bitumen adjustments receivable which have been netted against the gas over bitumen royalty obligation on the statement of financial position.

A reconciliation of the gas over bitumen royalty obligation is provided below:

Gas over bitumen royalty obligation	($thousands)
Balance, January 1, 2010	77,167
Royalty adjustments	10,454
Royalty adjustments on dispositions	(13,767)
Royalty adjustments not yet received	(3,357)
Balance, December 31, 2010	70,497
Royalty adjustments	4,772
Royalty adjustments not yet received	(564)
Balance, December 31, 2011	**74,705**

Exploration and evaluation

($thousands)	**2011**	2010	2009
Lease rentals	**3,879**	4,439	4,147
Seismic expenditures and dry hole costs	**3,917**	4,030	6,402
Lease expiries	**8,201**	9,824	11,289
Total exploration and evaluation	**15,997**	18,293	21,838

Exploration and evaluation ("E&E") costs include lease rentals on undeveloped acreage, seismic expenditures, exploratory dry hole costs and lease expiries. E&E costs decreased from $18.3 million in 2010 to $16.0 million in 2011 due to lower lease rental charges and lease expiries, consistent with the reduction in undeveloped land from year to year.

General and administrative expenses

		2011		2010		2009
	$thousands	**$/Mcfe**	$thousands	$/Mcfe	$thousands	$/Mcfe
Cash general & administrative	**30,094**	**0.58**	34,380	0.62	32,134	0.56
Share-based compensation [1]	**5,618**	**0.11**	5,283	0.09	7,481	0.13
Total general & administrative	**35,712**	**0.69**	39,663	0.71	39,615	0.69

(1) Non-cash item

General and administrative expenses ("G&A") include costs incurred by Perpetual which are not directly associated with the production of oil and natural gas. The largest components of G&A expenses are office staff compensation costs and information technology costs. Field employee compensation costs are charged to operating expenses. Overhead recoveries resulting from the allocation of administrative costs to producing properties and capital projects are recorded as a reduction of G&A expenses, and are a function of capital and operating expenditures during the year, as well as the Corporation's productive well base.

Cash G&A expenses, net of overhead recoveries on operated properties, decreased 12 percent to $30.1 million in 2011 from $34.4 million in 2010. The decrease is primarily due to reductions in the employee count and related salaries and consulting fees. Cash G&A in 2010 also included approximately $1.5 million in costs associated with the conversion from an income trust to a corporation. Cash G&A expenses decreased on a unit-of-production basis from $0.62 per Mcfe in 2010 to $0.58 per Mcfe in 2011.

Share-based compensation increased six percent in 2011 from 2010 levels, as higher restricted rights expense caused by an increase in rights granted was partially offset by lower share option expense due to a lower estimated fair value of share options granted. Fair values of share options are a function of the trading price of Perpetual's Common Shares.

Financing expenses

Interest expense on the 8.75% Senior Notes issued on March 15, 2011 totaled $10.9 million for the current year, of which $0.4 million relates to amortization of debt issue costs.

Interest on bank debt decreased to $6.6 million in 2011 from $12.2 million in 2010 as a result lower bank debt balances due to the issuance of Senior Notes during the year.

Interest on convertible debentures increased to $19.9 million in 2011 from $19.5 million in 2010, due to a full year of non-cash amortization of issue costs and accretion of the equity component of the 7.0% convertible debentures issued in May 2010. The cash component of interest on convertible debentures was unchanged at $16.3 million for both periods, as additional interest in 2011 on the 7.0% debentures was matched by interest expense recorded in 2010 on a series of 6.25% convertible debentures that matured on June 30, 2010.

Funds flow

Lower realized gains on derivatives were the primary factor in a decrease of 65 percent in the Corporation's funds flow netback from $4.26 per Mcfe in 2010 to $1.48 per Mcfe in 2011. Funds flow decreased by $160.5 million to $77.0 million ($0.52 per Common Share) for the year ended December 31, 2011 from $237.5 million ($1.69 per Common Share) in the 2010 period.

Depletion, depreciation and impairment

Depletion and depreciation ("D&D") expense decreased from $225.0 million ($4.05 per Mcfe) in 2010 to $116.1 million ($2.23 per Mcfe) in 2011. In 2010 and prior years, D&D expense was calculated based on proved developed reserves for exploration and development costs and total proved reserves for acquisition costs. The Corporation revised its estimate of the D&D rate of its oil and gas properties on January 1, 2011 to include probable reserves and associated future development and decommissioning costs. The effect of this change reduced D&D expense by $117.1 million compared to depletion and depreciation expense calculated in accordance with GAAP for the year ended December 31, 2010. Perpetual believes that proved and probable reserves are a better reflection of the useful life of the Corporation's assets.

At year-end 2011, capital assets included $111.6 million (2010 - $107.5 million) of E&E assets (of which $4.8 million was included in assets held for sale), consisting of undeveloped land and oilsands expenditures, not subject to depletion and $23.8 million (2010 - $23.8 million) of costs related to shut-in gas over bitumen reserves which are not being depleted due to the non-producing status of the wells in the affected properties. The increase in E&E assets during the year is driven by $25.8 million in expenditures on undeveloped land and oilsands evaluation, partially offset by lease expiries, sales of undeveloped land and transfers of land to developed PP&E.

At the end of each reporting period, Perpetual assesses its oil and natural gas properties, exploration and evaluation assets and gas storage facility for potential indicators of impairment. At December 31, 2011 indicators of potential impairment were identified and Perpetual measured the carrying values of each of its CGUs, less the corresponding decommissioning obligations, against the estimated value in use. An impairment loss of $25.6 million was recorded for 2011 (2010 - $24.3 million) as a result of this analysis.

Assets held for sale

As part of Perpetual's non-core disposition program, the Corporation has identified $20.3 million of oil and gas assets that were held for sale as of December 31, 2011. The assets held for sale do not represent a total amount of estimated dispositions in 2012, but are the potential dispositions that were deemed "highly probable" as of the reporting date. These properties were located primarily in the West Central and South districts, and the related dispositions were closed in the first quarter of 2012. Subsequent to year-end, Perpetual identified the WGSI Facility as an asset held for sale.

Decommissioning obligation

Perpetual estimates its total future decommissioning obligation based on net ownership interest in all wells, facilities and pipelines, including estimated costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimated timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated undiscounted total value of Perpetual's future decommissioning obligation is $326 million as at December 31, 2011. As at December

31, 2011, the undiscounted net salvage value of the Corporation's gas plants, compressors and facilities was estimated at $151 million. The McDaniel Report includes an undiscounted amount of $81 million with respect to expected future well abandonment costs related specifically to proved and probable reserves and such amount is included in the values captioned "Total proved and probable reserves" in the "NPV of reserves" table in this MD&A. The following table presents the estimated future abandonment and reclamation costs and estimated net salvage values at various discount rates.

Abandonment and reclamation costs

($millions, net to Perpetual)	**Undiscounted**	**5%**	**8%**	**Discounted at 10%**
Well abandonment costs for developed reserves included in McDaniel Report	55	32	25	21
Well abandonment costs for undeveloped reserves included in McDaniel Report	26	14	10	8
Well abandonment costs for total proved and probable reserves included in McDaniel Report	81	46	35	30
Estimate of other abandonment and reclamation costs not included in McDaniel Report	246	141	107	90
Total estimated future abandonment and reclamation costs	**326**	**188**	**142**	**120**
Salvage value	(151)	(87)	(66)	(55)
Abandonment and reclamation costs, net of salvage	**175**	**101**	**76**	**64**
Well abandonment costs for developed reserves included in McDaniel Report	(55)	(32)	(25)	(21)
Estimate of additional future abandonment and reclamation costs, net of salvage[(1)]	**121**	**69**	**52**	**43**

(1) Future abandonment and reclamation costs not included in the McDaniel Report, net of salvage value.

The decommissioning obligation presented in Perpetual's consolidated financial statements is discounted using an estimate of the timing of asset retirement expenditures and an average risk-free interest rate of 2.6 percent, which is based on Bank of Canada bond rates and reviewed at every reporting date. These expenditures are currently expected to occur over the next 25 years with the majority of costs incurred between 2015 and 2020. Perpetual's discounted decommissioning obligation increased from $236.2 million at December 31, 2010 to $247.7 million at December 31, 2011 primarily due to lower discount rates. Decommissioning obligations of $4.8 million related to assets held for sale were reclassified to current liabilities at December 31, 2011.

Income taxes

Perpetual recorded deferred tax expense of $1.6 million for 2011 (2010 - $2.1 million), related to timing differences between book and tax values of the Corporation's gas storage assets. The tax values of the Corporation's non-gas storage assets currently exceed the related book values. Deferred income tax is a non-cash item and does not affect the Corporation's funds flows or its cash position.

Tax pools

Tax pool information ($ millions)	**As at December 31, 2011**
Canadian oil and gas property expense (COGPE)	298
Canadian development expense (CDE)	161
Canadian exploration expense (CEE)	55
Undepreciated capital cost (UCC)	205
Share issue costs	3
Non-capital losses	166
Total	888

At December 31, 2011, the Corporation's consolidated income tax deductions are estimated to be $888 million. Actual tax deduction amounts will vary as tax returns are finalized and filed.

Net loss

The Corporation recorded a net loss of $95.9 million or $0.65 per basic and diluted Common Share in 2011 as compared to a net loss of $100.7 million or $0.72 per basic and diluted Common Share in 2010. The reduction in the net loss was due to lower D&D charges, offset by reduced funds flows. The prior year loss also included $40.5 million in interest on Trust Units, as distributions to Unitholders are expensed through earnings under IFRS.

LIQUIDITY, CAPITALIZATION, FUTURE OPERATIONS AND FINANCIAL RESOURCES

Capitalization and financial resources		Year ended December 31	
($ thousands except per Common Shares and percent amounts)	**2011**	2010	2009
Long term bank debt	**130,062**	182,612	262,393
Senior Notes, measured at principal amount	**150,000**	-	-
Convertible debentures, measured at principal amount	**234,897**	234,897	230,168
Adjusted working capital deficiency [(2)]	**7,627**	31,934	8,450
Net debt	**522,586**	449,443	501,011
Common Shares outstanding at end of period (thousands)	**146,966**	148,284	126,224
Market price at end of year	**1.17**	3.93	5.22
Market value of Common Shares	**171,950**	582,756	658,889
Total capitalization [(1)]	**694,536**	1,032,199	1,159,900
Net debt as a percentage of total capitalization (%)	**75.2**	43.5	43.2
Funds flow [(1)]	**76,986**	237,470	231,347
Net debt to funds flow ratio (times) [(1)]	**6.8**	1.9	2.2

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A.

(2) Adjusted working capital deficiency (surplus) excludes short-term derivative assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, assets and liabilities held for sale and share-based payment liabilities. Working capital deficiency does not include approximately $9.0 million in gas over bitumen royalty adjustments not yet received as of December 31, 2011.

Perpetual has a revolving credit facility with a syndicate of Canadian chartered banks (the "Credit Facility"). The revolving nature of the facility expires on May 29, 2012 if not extended. The borrowing base on the Credit Facility was reduced to $171 million from $190 million as a result of asset sales in the first quarter of 2012, with the next borrowing base review scheduled for April 2012. At current interest rates and applicable margins, the effective interest rate on the Corporation's bank debt is approximately 5.5 percent. Collateral for the credit facility is provided by a floating-charge debenture covering all existing and acquired property of the Corporation as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the facility. Bank debt drawn on Perpetual's credit facility decreased $52.6 million or 29 percent from December 31, 2010 due to the issuance of Senior Notes in 2011, partially offset by capital expenditures and dividends in excess of funds flows and net dispositions for the year.

Perpetual has an adjusted working capital deficiency of $7.6 million at December 31, 2011, as compared to a deficiency of $31.9 million at December 31, 2010. The decrease in the working capital deficiency is primarily related to lower WGSI capital spending in the fourth quarter of 2011 and the absence of dividends payable at December 31, 2011. The Corporation's working capital deficiency will be funded from future sales revenues and by additional borrowings from Perpetual's credit facility, as required.

Future operations

The Corporation has $75 million of 6.50% convertible unsecured subordinated debentures ("6.50% Debentures") maturing on June 30, 2012. While Perpetual may settle all or a portion of the outstanding 6.50% Debentures through the issuance of Common Shares by giving notice of such intent to Debentureholders not more than 30 and not less than 15 days prior to the maturity date, it is the intention of the Corporation to settle the 6.50% Debentures in cash.

To date in 2012, Perpetual has disposed of non-core oil and gas assets for total proceeds of approximately $61 million. In addition, as described in note 23 to the annual consolidated financial statements, the Corporation has identified the WGSI Facility as an asset held for sale subsequent to the balance sheet date. Perpetual anticipates that cash flows including cash flow from operating activities, proceeds from closed and future asset dispositions and available credit facilities will provide the required funds to discharge the Corporation's existing obligations, carry out exploration and development programs and fund ongoing operations for the foreseeable future, including the cash settlement of the 6.50% Debentures on the maturity date. Perpetual expects a downward adjustment to the borrowing base under the Credit Facility pursuant to the semi-annual redetermination of the borrowing base in April 2012, which relates principally to lower natural gas prices and the effects of asset dispositions. If available liquidity is not sufficient to meet the Corporation's operating and debt servicing obligations as they come due, management's plans include reducing expenditures as necessary or pursuing alternative financing arrangements for the foreseeable future.

Net debt to funds flow increased to 6.8 times for the year ended December 31, 2011 from 1.9 times for the year ended December 31, 2010 due to lower funds flows resulting from a reduction in gains on derivatives and higher overall debt levels. A reconciliation of the change in net debt from December 31, 2010 to December 31, 2011 is as follows.

Reconciliation of net debt ($ millions)	
Net debt, December 31, 2010	449.4
Capital expenditures (exploration and development, land acquisitions, gas storage and other)	151.0
Dispositions, net of acquisitions	(33.9)
Funds flow [(1)]	(77.0)
Dividends	28.9
Expenditures on asset retirement obligations	2.5
Repurchase of common shares	4.6
Issue costs on Senior Notes	3.8
Unrealized loss on marketable securities	2.6
Proceeds from gas storage arrangement, net of issue costs	(9.9)
Gas over bitumen royalty adjustments not yet received	0.6
Net debt, December 31, 2011	**522.6**

(1) These are non-GAAP measures; see "Other non-GAAP measures" in this MD&A.

Gas storage arrangement

As part of the Corporation's semi-annual borrowing base redetermination in May 2010, Perpetual's gas reserves in the Warwick Glauconitic-Nisku A pool were removed from the assets dedicated to secure the syndicated banking facility. In order to provide non-bank funding for a portion of the WGSI Facility, Perpetual has entered into a gas sale and storage transaction which includes the forward sale of these reserves, currently in the storage reservoir, that provide the "cushion" gas for the storage operation. In accordance with the storage arrangement funding, Perpetual received $31.6 million on June 30, 2010, and an additional $10 million (less $0.1 million in issue costs) in 2011. In exchange for the funds received, the Corporation has agreed to deliver 8 Bcf of natural gas to the counterparty during the first quarter of 2013. In 2011, Perpetual extended the delivery term to the first quarter of 2016 and subsequent to year-end has extended the term to 2018. The gas storage liability on the balance sheet combined with the related derivative asset represent the estimated net present fair value of the future delivery obligation and as such, the liability will be accreted until its maturity, using the effective interest rate method. In the current year the Corporation recorded an unrealized gain of $4.1 million (2010 - $3.7 million) on the statement of earnings (loss) related to the change in the forward price curves for natural gas.

Perpetual's future contractual obligations are summarized in the following table:

		Payments due by period			
Contractual obligations ($ millions)	Total	2012	2013-2014	2015-2016	Thereafter
Long-term bank debt [(1)]	130,062	-	130,062	-	-
Convertible debentures, principal	234,897	74,925	-	159,972	-
Senior notes, principal	150,000	-	-	-	150,000
Operating leases [(3)]	12,615	2,275	3,974	3,918	2,449
Pipeline commitments [(2)]	16,081	8,451	6,995	527	108
Total contractual obligations	543,655	85,651	141,031	164,417	152,557

(1) The revolving feature of Perpetual's credit facility expires on May 29, 2012 if not extended. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity date of one additional year.

(2) The Corporation has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada.

(3) Perpetual has office leases on its current office space ending on March 31, 2018. Office lease commitments are shown net of related sublease recoveries.

Convertible debentures

As at December 31, 2011, the Corporation 6.50% Debentures, 7.25 percent convertible debentures issued in April 2006 and amended in 2009 (7.25% Debentures) and 7.0 percent convertible debentures issued in May 2010 (7.0% Debentures). All series of debentures are repayable on the maturity date in cash or in Common Shares, at the option of Perpetual. Additional information on convertible debentures is as follows.

Convertible debentures	6.50%	7.25%	7.00%
Principal issued ($ millions)	75.0	100.0	60.0
Principal outstanding ($ millions)	74.9	100.0	60.0
Trading symbol on the Toronto Stock Exchange ("TSX")	PMT.DB.C	PMT.DB.D	PMT.DB.E
Maturity date	June 30, 2012	January 31, 2015	December 31, 2015
Conversion price ($ per Common Share)	14.20	7.50	7.00
Fair market value ($ millions)	72.5	80.0	45.7

Fair values of debentures are calculated by multiplying the number of debentures outstanding at December 31, 2011 by the quoted market price per debenture at that date. None of the debentures were converted into common shares during the year ended December 31, 2011.

All series of debentures are redeemable by the Corporation at a premium to face value, pay interest semi-annually and are subordinated to substantially all other liabilities of Perpetual including the credit facility. The 7.0% Debentures are also subordinated to all other series of convertible debentures.

Senior notes

On March 15, 2011 the Corporation issued $150 million of seven-year Senior Notes for net proceeds of $146.2 million after issue costs. The Senior Notes bear interest at 8.75%, are unsecured and mature on March 15, 2018. The Senior Notes are direct senior unsecured obligations of Perpetual ranking *pari passu* with all other present and future unsecured and unsubordinated indebtedness of the Corporation.

Shareholders' equity

Perpetual's total capitalization was $694.5 million at December 31, 2011. Net debt to total capitalization increased to 75.2 percent at December 31, 2011 as compared to 43.5 percent for the prior year as the trading price of the Corporation's Common Shares dropped by 70 percent during the year. In 2011 Perpetual had an active Normal Course Issuer Bid outstanding and repurchased a total of 1.6 million Common Shares from May to October 2011 at an average price of $2.93 per Common Share.

Weighted average Common Shares outstanding for 2011 totaled 147.7 million (2010 – 140.6 million). On December 31, 2011 there were 147.0 million Common Shares outstanding.

Dividends

Dividends for the year ended December 31, 2011 totaled $28.9 million or $0.195 per Common Share, as compared to $78.6 million or $0.56 per common share for 2010. On October 19, 2011 the Corporation announced that future dividend payments would be suspended until further notice. Continued payment of a dividend is not sustainable given the continued weakness in natural gas prices, and will inhibit Perpetual's continuing efforts to implement its strategy of commodity and asset base diversification.

Notwithstanding a dramatic decrease in natural gas prices from June of 2008 forward, and the fact that Perpetual's production was composed almost entirely of conventional shallow natural gas, the Corporation has to date been able to issue cumulative dividends (including distributions paid since the inception of Perpetual's successor, Paramount Energy Trust) of $14.519 per Common Share. The historic decline in natural gas prices and related funds flow reductions were offset in large part through a successful hedging program, which contributed to the Corporation being able to continue paying a dividend while pursuing its asset base diversification strategy. However, going forward, persistent growth in North American natural gas supply, coupled with relatively soft demand, suggest that a recovery in gas prices may be further delayed. As favorable natural gas economic hedging opportunities are no longer available in the current market, directing funds flow to the execution of the diversification strategy is paramount. Perpetual believes that its asset and commodity diversification strategy is central to preserving and growing value for Shareholders.

The continued execution of the strategies to diversify commodity mix and create value, capitalizing on Perpetual's substantial inventory of economic opportunities, is expected to grow funds flow. Combined with ongoing debt reduction initiatives, including asset sales, stronger diversified funds flows will strengthen the Corporation's balance sheet. The suspension of the dividend was necessary to drive Perpetual's commitment to maximize Shareholder value.

Reinstatement of a dividend in the future will be evaluated at such time as Perpetual's balance sheet has regained strength and commodity prices and costs support a sustainable model where excess free funds flow, over and above capital investments, is once again being generated for distribution to Shareholders.

2011 dividends by month ($ per Common Share) Payment Date	Dividend
February 15, 2011	0.03
March 15, 2011	0.03
April 15, 2011	0.03
May 16, 2011	0.03
June 15, 2011	0.015
July 15, 2011	0.015
August 15, 2011	0.015
September 15, 2011	0.015
October 17, 2011	0.015
Total (1)	**0.195**

(1) Total is based upon cash dividends declared during 2011.

SUMMARY OF QUARTERLY RESULTS

				Three months ended
($ thousands except where noted)	**Dec 31, 2011**	Sept 30, 2011	June 30, 2011	Mar 31, 2011
Oil and natural gas revenues (1)	**61,412**	58,400	67,097	60,900
Production (MMcfe/d)	**142.9**	135.5	150.3	140.7
Funds flow (2)	**15,893**	19,318	17,852	23,923
Per common share - basic	**0.11**	0.13	0.12	0.16
Net earnings (loss)	**(38,691)**	(24,343)	(5,626)	(27,260)
Per common share - basic	**(0.26)**	(0.17)	(0.04)	(0.18)
- diluted	**(0.26)**	(0.17)	(0.04)	(0.18)
Realized commodity price ($/Mcfe) (3)	**4.66**	4.46	4.61	4.68
Average AECO Monthly Index price ($/Mcf)	**3.44**	3.72	3.74	3.77

				Three months ended
($ thousands except where noted)	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010
Oil and natural gas revenues (1)	61,718	61,254	64,108	73,139
Production (MMcfe/d)	145.1	151.0	165.2	149.2
Funds flow (2)	70,509	46,078	36,162	84,419
Per common share – basic (4)	0.48	0.32	0.25	0.66
Net earnings (loss)	(28,193)	(16,260)	(76,878)	20,612
Per common share – basic (4)	(0.19)	(0.11)	(0.54)	0.16
- diluted	(0.19)	(0.11)	(0.54)	0.15
Realized commodity price ($/Mcfe) (3)	7.83	6.18	5.54	9.78
Average AECO Monthly Index price ($/Mcf)	4.13	3.72	3.86	5.36

(1) Excludes realized gains (losses) on derivatives, but includes gas storage revenue.
(2) These are non-GAAP measures; see "Other non-GAAP measures" in this MD&A.
(3) Realized natural gas price includes realized gains and losses on financial hedging and physical forward sales contracts, and oil and natural gas liquids revenues measured on a per Mcfe basis.
(4) Earnings (loss) is measured per Trust Unit outstanding for the first two quarters of 2010.

Oil and natural gas revenues are primarily a function of production levels and commodity prices before hedging. Revenues were highest in the first quarter of 2010 when AECO prices were highest, averaging $5.36 per Mcf. Perpetual uses derivatives as part of its risk management strategy to mitigate the effect of volatility in AECO prices on funds flows, and in recent quarters has shifted its asset development strategy to focus on oil and liquids-rich natural gas. Therefore funds flows will trend with Perpetual's production mix, realized commodity price and changes in production levels. Funds flows were highest in the first and fourth quarters of 2010 as a result of realized commodity prices of $9.78 and $7.83 per Mcfe, respectively. Funds flows are lowest in the fourth quarter of 2011 due to lower AECO prices and a reduction in realized derivative gains relative to previous quarters, leading to a realized commodity price of $4.66 per Mcfe.

Net earnings (loss) are a function of funds flows and non-cash charges such as D&D, impairment losses and unrealized gains (losses) on derivatives. Due to the volatility of natural gas prices and the Corporation's risk management position, net earnings (losses) also fluctuated with changes in AECO gas prices as of each balance sheet date. Net earnings were highest in the first quarter of 2010 as a result of high funds flows and unrealized gains on derivatives of $16.7 million. The net loss in the second quarter of 2010 resulted from an unrealized loss of $34.4 million on the change in mark-to-market value of Perpetual's derivatives during the period. Distributions paid in the first two quarters of 2010 were expensed through earnings, whereas dividends paid after the conversion to a corporation were direct reductions in equity. Net losses in the 2011 quarters are primarily due to low gas prices and the absence of significant realized gains on derivatives, which results in the Corporation's funds flow netback in those periods being less than non-cash charges such as D&D and accretion on decommissioning obligations.

2012 OUTLOOK AND SENSITIVITIES

Perpetual is nearing completion of a $34 million capital spending program for the first quarter of 2012. Capital expenditures were directed principally toward the advancement of Perpetual's two key commodity diversifying plays: horizontal development of the Wilrich in greater Edson, and exploration and development of heavy oil at Mannville.

- Two horizontal and one vertical (2.3 net) wells were drilled at Edson, in addition to facility construction to tie-in new production
- Two vertical and 12 horizontal (14.0 net) wells were drilled and tied-in at Mannville, and tie-in operations were completed for one well drilled in 2011.

As gas prices reached levels below $3.00 per Mcf in mid-January, investment in all natural gas projects including the Wilrich program was suspended and funds were redirected to the highly profitable Mannville heavy oil activities.

The Corporation's Board of Directors has approved a capital spending budget to remain within funds flow for 2012. Capital activity for the remainder of the year will be focused on Mannville heavy oil exploration and development.

Incorporating production additions from these capital expenditures, the following table shows Perpetual's estimate of funds flow for 2012 based on its current hedging portfolio and cost estimates under several different full year 2012 AECO gas price and WTI oil price assumptions, and incorporating all non-core property dispositions closed to date in 2012. Perpetual estimates 2012 annual production of 3,600 bbl/d of oil and NGL, 103 MMcf/d of natural gas, a $28 per bbl differential between WTI and WCS reference prices, $96 million in operating costs, $28 million in cash G&A expenses and a 5.5 percent interest rate on long-term bank debt.

The following table outlines estimated funds flow at various assumed commodity prices:

Funds Flow ($millions) **AECO Gas Price ($/GJ)**

		$1.75	**$2.10**	**$2.50**	**$2.75**	**$3.00**
Edmonton oil price ($/bbl)	**$80.00**	30	32	34	35	36
	$90.00	33	35	37	38	39
	$100.00	37	39	40	42	43
	$110.00	37	39	40	42	43
	$120.00	37	39	40	42	43

Below is a table that shows sensitivities of Perpetual's 2012 estimated funds flow to operational changes and changes in the business environment:

Funds flow sensitivity analysis ($ per Common Share)	Change	Impact on funds flow per Common Share	
		Annual	Monthly
Business Environment			
Natural gas price at AECO	$0.25 per Mcf	0.058	0.005
Oil price at WTI	$5.00 per bbl	0.041	0.003
Interest rate on bank debt	1%	0.007	0.001
Operational			
Natural gas production	5 MMcf/d	0.012	0.001
Oil and NGL production	100 bbl/d	0.029	0.002
Operating costs	$0.10 per Mcfe	0.0266	0.002
Cash general and administrative expenses	$0.10 per Mcfe	0.0266	0.002

CORPORATE GOVERNANCE

The Corporation is committed to maintaining high standards of corporate governance. Each regulatory body, including the Toronto Stock Exchange, the Canadian provincial securities commissions and the Securities and Exchange Commission ("SEC"), whose responsibilities include implementing rules under the United States Sarbanes-Oxley Act of 2002, has a different set of rules pertaining to corporate governance. The Corporation fully conforms to the rules of the governing bodies under which it operates.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As at December 31, 2011, an evaluation of the effectiveness of Perpetual's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that, as at December 31, 2011, the design and operation of Perpetual's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Corporation in reports filed with, or submitted to, securities regulatory authorities is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure and were effective to provide reasonable assurance that such information is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's Annual Report on Internal Control over Financial Reporting

Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with GAAP.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting was effective as at December 31, 2011, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2011, there was no change in Perpetual's internal control over financial reporting that materially affected or is reasonably likely to materially affect Perpetual's internal control over financial reporting.

CEO and CFO Certifications

Perpetual's President and Chief Executive Officer and Chief Financial Officer have filed with the Canadian securities regulators the SEC certifications regarding the quality of Perpetual's public disclosures relating to its fiscal 2011 reports filed with the Canadian securities regulators and the SEC.

NON-GAAP MEASURES

Payout ratio

Payout ratio refers to dividends measured as a percentage of funds flow for the period and is used by management to analyze funds flow available for development and acquisition opportunities as well as overall sustainability of dividends. Funds flow does not have any standardized meaning prescribed by GAAP and therefore payout ratio may not be comparable to the calculation of similar measures for other entities.

Operating and funds flow netbacks

Operating and funds flow netbacks are used by management to analyze margin and funds flow on each Mcfe of oil and natural gas production. Operating and funds flow netbacks do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to the calculation of similar measures for other entities. Operating and funds flow netbacks should not be viewed as an alternative to funds flow from operations, net earnings (loss) per common share or other measures of financial performance calculated in accordance with GAAP.

Revenue, including realized gains (losses) on derivatives

Revenue, including realized gains (losses) on derivatives, includes call option premiums received and is used by management to calculate the Corporation's net realized commodity prices taking into account monthly settlements on financial forward sales, collars and foreign exchange contracts. These contracts are put in place to protect Perpetual's funds flows from potential volatility in commodity prices, and as such any related realized gains or losses are considered part of the Corporation's realized price. Revenue, including realized gains (losses) on derivatives does not have any standardized meaning as prescribed by GAAP and should not be reviewed as an alternative to Revenue or other measures calculated in accordance with GAAP.

Net debt and net bank debt

Net bank debt is measured as bank debt including net working capital (deficiency) excluding short-term derivative assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, restricted cash and liabilities related to Perpetual's stock option plan. Net debt includes Senior Notes and convertible debentures, measured at principal amount. Net bank debt and net debt are used by management to analyze leverage. Net bank debt and net debt do not have any standardized meaning prescribed by GAAP and therefore these terms may not be comparable with the calculation of similar measures for other entities.

Total capitalization

Total capitalization is equal to net debt plus market value of issued equity and is used by management to analyze leverage. Total capitalization as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Corporation.

NEW ACCOUNTING STANDARDS

Transition to IFRS

Effective January 1, 2011, GAAP as accepted in Canada prior to 2011 ("Previous GAAP") has been conformed to IFRS for publicly accountable enterprises, with a transition date of January 1, 2010. The Corporation's interim financial statements for the periods ended March 31, 2011, June 30, 2011 and September 30, 2011 were prepared in accordance with IFRS 1 – First-time Adoption of International Financial Reporting Standards and IAS 34, Interim Financial Reporting. Comparative information for 2010 is presented using IFRS unless otherwise noted.

Perpetual's accounting policies are presented in note 2 to the annual consolidated financial statements for the year ended December 31, 2011, and note 23 to annual consolidated financial statements contains reconciliations between the Corporation's financial position, financial performance and cash flows under IFRS and under Previous GAAP.

In accordance with IFRS 1, Perpetual elected to apply certain exemptions available on first-time adoption of IFRS, as follows.

Business combinations

The Corporation applied the IFRS 1 exemption for business combinations. This allows the Corporation not to restate its previously recorded business combinations incurred under Previous GAAP before the January 1, 2010 transition date. In applying this exemption the Corporation has reviewed its statements of financial position and operations for any items that would require additional recognition or reclassification namely property, plant, and equipment, intangible E&E assets, leases, and provisions.

Borrowing costs

The Corporation elected to apply IAS 23 borrowing costs and capitalized borrowing costs from an effective date of August 1, 2009. This date coincides with the onset of development of the Warwick natural gas storage reservoir.

Borrowing costs associated with this development and subsequent facility construction after August 1, 2009 are capitalized prospectively.

Embedded derivative in convertible debentures

The Corporation has elected to apply the exemption in IFRS 1 not to restate the embedded derivative portion of the convertible debentures no longer outstanding as of January 1, 2010.

Leases

The Corporation elected the exemption in IFRS 1 that allows the Corporation to evaluate any contracts to determine whether in fact they are leases according to circumstances that existed at the transition date. The Corporation's leases were not reassessed to determine whether an arrangement contained a lease under International Financial Reporting Interpretations Committee 4, "Determining whether an Arrangement contains a Lease" for contracts that were already assessed under Previous GAAP.

Share based payments

IFRS 2 - Share Based Payments has not been applied to equity instruments related to share based compensation arrangements that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010. For cash-settled share based payment arrangements, the Corporation has not applied IFRS 2 to liabilities that were settled before January 1, 2010.

Changes in accounting policies

Significant accounting policy differences between IFRS and Previous GAAP relate primarily to property, plant and equipment, decommissioning obligations and derivatives. Specific policy differences are as follows.

Exploration and evaluation assets

Under Previous GAAP, the Corporation followed the successful efforts method of accounting for oil and natural gas operations. Under this method, the Corporation capitalized only those costs that result directly in the discovery of oil and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, were charged to net earnings or loss as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, were capitalized. Unproved properties were carried at cost, amortized over the average lease term and tested for impairment annually, with any carrying amount in excess of fair value charged to net earnings or loss. The net cost of unproductive wells, abandoned wells and surrendered leases were charged to net earnings or loss in the year of abandonment or surrender.

In accordance with IFRS 6 – Exploration for and Evaluation of Mineral Resources, the Corporation assessed the classification of activities designated as E&E which then determines the appropriate accounting treatment and classification of the costs incurred.

Property, plant and equipment

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, remained the same under IFRS as Previous GAAP, adjusted only to segregate E&E expenditures, to adjust asset cost for revised decommissioning obligations and to record gains (losses) on dispositions under IFRS.

Under Previous GAAP, proceeds from dispositions were deducted from the successful efforts cost pool without recognizing a gain or loss unless the deduction resulted in a change to the depletion rate of 20 percent or greater, in which case a gain or loss was recorded.

Under IFRS, gains or losses are recorded on dispositions and are calculated as the difference between the proceeds and the net book value of the assets disposed.

Depletion and depreciation

Under Previous GAAP Perpetual used proved developed reserves as the basis for depleting exploration and development costs, and total proved reserves as the basis for depleting acquisition costs. Under IFRS, the Corporation has elected to use proved plus probable reserves, incorporating future development costs, as the basis for depleting all oil and gas capital costs. As a result, the Corporation's depletion rate per Mcfe of production has decreased compared to previous periods, and D&D expense has also decreased. This change was made effective January 1, 2011.

Decommissioning obligations

Decommissioning obligations (asset retirement obligations) had been measured under Previous GAAP based on the estimated future cost of decommissioning, discounted using a credit-adjusted risk free rate, however under IFRS the liability was required to be re-measured based on changes in estimates including discount rates. The Corporation has chosen a risk free rate as the appropriate discount rate for calculating all decommissioning obligations under IFRS. Perpetual restated the amount of decommissioning obligations as of the IFRS transition date of January 1, 2010 to reflect a risk free interest rate which varied from 1.92 to 4.08 percent over the period of time since the inception of the Corporation. The corresponding increase to the decommissioning liability at the transition date resulted in higher depletion and depreciation expense and lower accretion expense as well as adjustments to the gain on dispositions of property, plant, and equipment in 2010.

Asset and goodwill impairment

Under Previous GAAP, asset impairment is a two-stage test, where the carrying amount of the asset is first compared to the sum of the expected undiscounted future cash flows; if the first test indicates that an impairment exists, then the impairment loss recorded is measured as the difference between the carrying amount and the fair value. Under IFRS, assets are separated into cash-generating units (CGUs), and the greater of value in use and fair value less costs to sell is used both to gauge the likelihood of and record the amount of the impairment. As a result of applying IFRS, the Corporation recorded impairment charges of $24.3 million to its statement of earnings for 2010. Impairment losses can also be reversed under IFRS, which is not permitted under Previous GAAP.

As part of its transition to IFRS, the Corporation elected to restate only those business combinations that occurred on or after January 1, 2010. In respect of acquisitions prior to January 1, 2010, goodwill represents the amount recognized under the Corporation's previous accounting framework. At January 1, 2010, the Corporation carried out an impairment test on its goodwill at the CGU level. The Corporation derecognized $23.1 million of goodwill previously recorded on an acquisition assigned to properties disposed prior to January 1, 2010.

Trust units and convertible debentures

For the first six months of 2010, where Perpetual was an income trust, its Trust Units did not qualify as equity instruments under IFRS guidelines, and were classified as liabilities on the Trust's IFRS statements of financial position dated January 1, 2010 and March 31, 2010. The Trust Units were not considered a derivative and were carried at cost on the statement of financial position under Previous GAAP prior to conversion to a corporation. As a result of this classification, trust unit distributions were recorded as interest expense in Perpetual's statement of earnings for the first six months of 2010. This conclusion also affects the accounting for unit incentive-based compensation and the portion of the convertible debentures that reflect the option to convert the debenture to trust units, both of which were recorded in equity under Previous GAAP but were classified as liabilities for the first six months of 2010, and fair valued every reporting date. Subsequent to Perpetual's conversion to a corporation, common shares outstanding are classified as equity in the Corporation's financial statements.

Share based payments

Prior to the corporate conversion Perpetual had a unit incentive plan ("Unit Incentive Plan"), which was accounted for as a liability-settled award for IFRS due to the trust units being considered liabilities. A liability was recorded on the statement of financial position at January 1, 2010 for the estimated fair value of the rights issued under the plan. The liability was then fair valued every reporting date, with changes in fair value being charged or credited to earnings. Under Previous GAAP, grants under the Unit Incentive Plan were treated as equity-settled awards due to the treatment of trust units as equity.

Upon conversion to a corporation the Unit Incentive Plan was replaced with the Share Option Plan ("Share Option Plan"), and Perpetual implemented a dividend bonus arrangement ("Dividend Bonus Arrangement"), whereby holders of Share Options would, upon exercising the Share Options, receive a cash payment equal to the total dividends declared on the number of Share Options exercised. Under IFRS the Share Option Plan is accounted for as an equity-settled award, and the Dividend Bonus Arrangement is accounted for as a liability-settled award. Both components are fair valued at the grant date, but the dividend bonus portion is re-fair valued every reporting date with changes in value being charged or credited to earnings, while the grant date fair values of the Share Options are expensed over the estimated life of the option. Under Previous GAAP, the Share Option Plan and Dividend Bonus Arrangement were treated as one liability-settled plan, and fair valued every reporting period.

In accordance with IFRS the graded vesting feature of the Share Options and estimated forfeiture rates must be reflected in the grant date fair values, whereas under Previous GAAP grants were fair valued as one tranche and forfeitures were accounted for as they occurred.

Accounting standards issued but not yet adopted

In 2011, the International Accounting Standards Board ("IASB") issued five new standards and an amendment. Five of these items relate to consolidation, while the remaining standard addresses fair value measurement. The new standards are effective for annual periods beginning on or after January 1, 2015. Early adoption is permitted.

IFRS 9, "Financial Instruments" is a result of the first phase of the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

IFRS 10, "Consolidated Financial Statements" replaces IAS 27 "Consolidated Separate Financial Statements". It introduces a new principle-based definition of control, applicable to all investees to determine the scope of consolidation. The standard provides the framework for consolidated financial statements and their preparation based on the principle of control.

IFRS 11 "Joint Arrangements" replaces IAS 31, "Interests in Joint Ventures". IFRS 11 divides joint arrangements into two types, each having its own accounting model. A "joint operation" continues to be accounted for using proportionate consolidation, where a "joint venture" must be accounted for using equity accounting. This differs from IAS 31, which offered the choice to use proportionate consolidation or equity accounting for joint ventures. A "joint operation" is defined as the joint operators having rights to the assets, and obligations for the liabilities, relating to the arrangement. In a "joint venture", the joint venturers have rights to the net assets of the arrangement, typically through their investment in a separate joint venture entity.

IFRS 12 "Disclosure of Interests in Other Entities" is a new standard, which combines all of the disclosure requirements for subsidiaries, associates and joint arrangements, as well as unconsolidated structured entities.

IFRS 13 "Fair Value Measurement" is a new standard meant to clarify the definition of fair value, provide guidance on measuring fair value and improve disclosure requirements related to fair value measurement.

IAS 28 "Investments in Associates and Joint Ventures" has been amended as a result of the issuance of IFRS 11 and the withdrawal of IAS 31. The amended standard sets out the requirements for the application of the equity method when accounting for interest in joint ventures, in addition to interests in associates.

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Corporation's consolidated financial statements which have been prepared in Canadian dollars in accordance with GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Perpetual bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

Accounting for petroleum and natural gas operations

The Corporation capitalizes all costs that result directly in the discovery of petroleum and natural gas reserves including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Geological and geophysical costs, lease rentals and exploratory dry holes are charged to net earnings in the period incurred. Capitalized costs that are exploratory in nature such as undeveloped land acquisitions, oilsands evaluation expenditures and exploration drilling are included in E&E costs, while development and construction costs are included in property, plant and equipment. Costs are transferred from E&E to property, plant and equipment once technical feasibility and commercial viability of the underlying resource have been established. Accounting for petroleum and natural gas operations requires management's judgment to determine the proper designation of wells as either developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of land in a given area.

Reserve estimates

Estimates of the Corporation's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Canadian Securities Administrators. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

Perpetual's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations. The estimates of reserves impact depletion, impairment, dry hole expenses and decommissioning obligations.

Business combinations

The acquisition 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 acquisition of control. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the recognized amount of the net assets acquired, the difference is recognized as a bargain purchase gain in net earnings or loss.

Derivatives

Fair values of derivatives such as forward sales contracts, the gas storage obligation and share based payment liabilities are based on mark-to-market assessments and estimates of fair values, which are subject to management's judgment and measurement uncertainty. Fair values of Share Options are calculated using a binomial lattice option pricing model and involve assumptions such as volatility, expected option life and expected dividend yield.

The Corporation uses estimates to allocate the debenture proceeds from convertible debenture issuances between debt and the derivative debenture liability or equity components, as appropriate.

Impairment of petroleum and natural gas properties

The Corporation reviews its proved properties for impairment on a CGU basis. For each property, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of that property may not be recoverable. The impairment provision is based on the excess of carrying value net of decommissioning obligation over the greater of value in use or fair value less costs to sell. Reserve estimates and estimates for natural gas prices and production costs may change and there can be no assurance that impairment provisions will not be required in the future.

Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales impacts the amount and timing of impairment provisions.

Decommissioning obligations

The decommissioning obligations recorded in the consolidated financial statements are based on the estimated total costs for future site restoration and abandonment of the Corporation's oil and natural gas properties and gas storage facilities, discounted at a risk-free interest rate. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, the timing of expenditures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors including changing technology and political and regulatory environments. The appropriate risk-free discount rate is selected based on estimated timing to reclamation and is subject to change as the estimated timelines change. The decommissioning obligations do not include any adjustment for the net salvage value of tangible equipment and facilities.

NOTES PERTAINING TO THE REPORTING OF BITUMEN CONTINGENT RESOURCE

The following are excerpts from the definitions of resources and reserves, contained in Section 5 of the COGE Handbook, which is referenced by the Canadian Securities Administrators in National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities".

Definitions

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. [Criteria for determining commerciality are further detailed in the COGE Handbook Section 5.3.4].

Discovered Petroleum Initially-In-Place (DPIIP) (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

Economic Contingent Resources are those contingent resources which are currently economically recoverable.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Undiscovered Petroleum Initially-In-Place (UDPIIP) (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources"; the remainder as unrecoverable.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Uncertainty Categories for Resource Estimates

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

Levels of Certainty for Reported Reserves

With respect to contingent resources, not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.

Risk Factors

In general, estimates of gross original resources and recoverable resources are based upon a number of factors and assumptions made as of the date on which the estimates were determined, such as geological, technological and engineering estimates and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those anticipated in forward-looking estimates.

These risks and uncertainties include but are not limited to: (1) the fact that there is no certainty that the zones of interest will exist to the extent estimated or that the zones will be found to have oil with characteristics that meet or exceed the minimum criteria in terms of net pay thickness, porosity or oil saturation, or that the oil will be commercially recoverable to the extent estimated; (2) risks inherent in the heavy oil and oil sands industry; (3) the lack of additional financing to fund the Corporation's exploration activities and continued operations; (4) fluctuations in foreign exchange and interest rates; (5) the number of competitors in the oil and gas industry with greater technical, financial and operations resources and staff; (6) fluctuations in world prices and markets for oil and gas due to domestic, international, political, social, economic and environmental factors beyond the Corporation's control; (7) changes in government regulations affecting oil and gas operations and the high compliance cost with respect to governmental regulations; (8) potential liabilities for pollution or hazards against which the Corporation cannot adequately insure or which the Corporation may elect not to insure; (9) the Corporation's ability to hire and retain qualified employees and consultants; (10) contingencies affecting the classification as reserves versus resources which relate to the following issues as detailed in the COGE Handbook: ownership considerations, drilling requirements, testing requirements, regulatory considerations, infrastructure and market considerations, timing of production and development, and economic requirements; (11) the fact that there is no certainty that any portion of contingent resources will be commercially viable to produce; (12) the fact that there is no certainty that any portion of the prospective resources will be discovered and if discovered, there is no certainty that it will be commercially viable to produce any portion of the resources; and (13) other factors beyond the Corporation's control. Any reference in this press release to DPIIP, UDPIIP, contingent resources and prospective resources are not, and should not be confused with oil and gas reserves.

RISK FACTORS

Perpetuals operations are affected by a number of underlying risks, both internal and external to the Corporation. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Corporation’s financial position, results of operations, and cash available for distribution to Shareholders are directly impacted by these factors.

Changes in tax legislation

Income tax laws, or other laws or government incentive programs relating to the natural gas industry such as resource taxation may be changed or interpreted in a manner that adversely affects us and our Shareholders. Tax authorities having jurisdiction over us or our Shareholders may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment or to the detriment of Shareholders.

Shut in natural gas reserves as a result of gas over bitumen issues

Recent decisions by the AEUB have brought into question our ability to continue to produce natural gas from all of the Wabiskaw and McMurray formations in certain parts of the Athabasca Oil Sands Area in Northeast Alberta. The AEUB has ordered shut-in of some of our production and reserves in this area.

The AEUB has also indicated that it believes there is a need to assess whether additional gas production should be curtailed in situations similar to those considered at hearings to-date and whether there is a need for a broad bitumen conservation strategy in all areas where natural gas production may interfere with eventual bitumen recovery. It is possible that such a strategy, when drafted and implemented by the ERCB (formerly AEUB), will affect future natural gas production from reservoirs owned by the Corporation and located within the gas over bitumen areas of concern as gas production from a portion or all of these zones may be identified in the future as posing a potential concern with respect to communication with potentially recoverable bitumen resources.

While we have no significant additional production recommended for shut-in by any party or the ERCB at this time and royalty adjustments are being received for most production currently shut-in, we cannot ensure that additional production will not be shut-in in the future or that we will be able to negotiate adequate compensation for having to shut-in any such production. This could have a material adverse effect on our funds flows and earnings.

Solution gas ownership

A portion of Perpetual's natural gas production is from properties where third parties hold bitumen rights. Certain of these third parties have suggested that "solution gas" exists within the bitumen and that therefore this solution gas is the property of the bitumen rights holder. If this is proven to be correct, and if it is demonstrated that this solution gas has been or may continue to be produced in association with the recovery of Perpetual's conventional natural gas rights, these facts may give rise to a third party claim for compensation. A successful claim in this regard may have a material adverse effect on the Corporation's business, financial condition and operations.

Exploration, development and production risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Substantial capital expenditures are required for exploration, development and production of oil and natural gas reserves in the future. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Prices, markets and marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the

United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

The Corporation manages commodity price uncertainty through financial hedges and physical forward sale arrangements. There is a credit risk associated with counterparties with which the Corporation may contract.

Failure to realize anticipated benefits of acquisitions and dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and

- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation also competes with other companies for all of its business inputs including exploitation and development prospects, access to commodity markets, property and corporate acquisitions, and available capital. The Corporation endeavours to be competitive by maintaining a strong financial condition through attracting and retaining technically competent and accountable staff, by refining and enhancing business processes on an ongoing basis and by utilizing current technologies to enhance exploitation, development and operational activities. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations which it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require additionalexpenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Variations in foreign exchange rates and interest rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares.

Additional funding requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Availability of drilling equipment and access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date, and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-political risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil and natural gas. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have an impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Management of growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of licenses and leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Cyclical and seasonal impact on industry

The Corporation's operational results and financial condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors including weather and general economic conditions, as well as conditions in other oil and natural gas producing regions. Any decline in natural gas prices could have an adverse effect on the Corporation's financial condition.

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity which could impact the production and future revenues of the Corporation. In addition high demand for equipment in winter months for areas limited to winter access could result in increased costs and the inability to execute the Corporation's desired exploration and development programs.

Third party credit risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, commodity price and currency hedge contract counterparties, and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the Alberta Business Corporations Act.

Reliance on key personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Administrator.

Operations in other jurisdictions and other business activities

Our operations and the expertise of our management are currently focused on conventional shallow and unconventional tight gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, the Articles of Incorporation does not limit the activities of the Corporation to oil and gas production and development, and the Corporation could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present new additional risks or alternatively, increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Corporation being adversely affected. In either case, our future operational and financial conditions could be materially adversely affected.

Lender limitations on dividends on common shares

Under the terms of the credit facility with our lenders, if the lenders determine that our borrowing base under the facility has been exceeded by the amount loaned and assuming there is not a demand for repayment we will be precluded from paying dividends until our borrowing base no longer is in a shortfall position. Our lenders may also restrict our ability to pay dividends when we are in breach or default of agreements with the lenders.

The lenders will be provided with security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as bankruptcy, the lender may foreclose on or sell the working interests.

Dilution

To maintain or expand our natural gas reserves we will need to finance capital expenditures and property acquisitions. Consequently, you may suffer dilution as a result of any future offering of common shares or securities convertible into common shares.

GAAP

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in our consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Corporation’s common shares. The carrying value of property, plant and equipment, the carrying value of goodwill and the value of hedging instruments are some of the items which are subject to valuation and potential non-cash write-downs.

Permitted investments

We may invest in certain permitted investments of which the market value may fluctuate. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Other permitted investments in energy-related entities will be subject to the general risks of investing in equity securities. These include the risks that the financial condition of issuers may become impaired or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors including: governmental, environmental and regulatory policies; inflation and interest rates; economic cycles; and global, regional and national events. The value of the Common Shares could be affected by adverse changes in the market values of permitted investments.

Changes in dividends

The board of directors of the Corporation assess the dividend on a monthly basis based on cash flow projections which incorporate Perpetual's base production forecasts, current hedges and physical forward natural gas sales, the forward market for natural gas prices, and the Corporation's capital spending program and projected production additions. Future dividends are subject to change as dictated by changes in commodity price markets, operations and future business development opportunities and may vary materially from previous dividends.

Operational matters

The Corporation's operations may be delayed or unsuccessful for many reasons including cost overruns, lower natural gas prices, equipment shortages, mechanical and technical difficulties and labour problems. The Corporation's operations will also often require the use of new and advanced technologies which can be expensive to develop, purchase and implement and may not function as expected. Perpetual may experience substantial cost overruns caused by changes in the scope and magnitude of our operations, employee strikes and unforeseen technical problems including natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions giving rise to liability to third parties. In particular, drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. Drilling for natural gas could result in unprofitable efforts, not only from dry wells but from wells that are productive but do not produce enough net revenue to return a profit after drilling, operating and other costs. The costs of drilling, completing and operating wells are often uncertain. In addition, our operations depend on the availability of drilling and related equipment in the particular areas where exploration and development activities will be conducted. Demand for the equipment or access restrictions may affect the availability of that equipment and, consequently, delay operations.

Continuing production from a property, and to some extent marketing of production therefrom, is largely dependent upon economic variables and the ability of the operator of the property. Operating costs on most properties have increased over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to certain properties. A reduction in dividends on Common Shares could result in such circumstances.

Expansion of operations

The operations and expertise of management of the Corporation are currently focused on natural gas production and development in the Western Canadian Sedimentary Basin. In the future, the Corporation may acquire oil and gas properties outside this geographic area. In addition, the Articles of Incorporation does not limit the activities of the Corporation to oil and gas production and development, and the Corporation could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present new additional risks or alternatively, increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Corporation being adversely affected.

Acquisitions

The price paid for asset acquisitions is based on the Corporation's internal assessment of the reserves and future production potential adjusted for risk. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas, and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Corporation. In particular, changes in prices of and markets for petroleum and natural gas from those anticipated at the time of making such assessments will affect the amount of future dividends and as such the value of the Common Shares. In addition, all such estimates involve a measure of geological and engineering uncertainty which could result in lower production and reserves than attributed to the working interests. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact funds flows and dividends to Shareholders.

Net asset value

The net asset value of the assets of the Corporation will vary from time to time dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Common Shares from time to time are also determined by a number of factors that are beyond the control of management and such trading prices may vary from the net asset value of the Corporation’s assets.

Financial instruments

The nature of Perpetual's operations results in exposure to fluctuations in commodity prices. The Corporation will monitor and, when appropriate, utilize derivative financial instruments and physical delivery contracts to mitigate its exposure to these risks. Perpetual may be exposed to credit-related losses in the event of non-performance by counter-parties to the financial instruments. From time to time the Corporation may enter into risk management activities in an effort to mitigate the potential impact of declines in natural gas prices. These activities may consist of, but are not limited to:

- buying a price floor under which the Corporation will receive a minimum price for natural gas production;
- buying a collar under which the Corporation will receive a price within a specified price range for natural gas production;
- selling call options to third parties, giving them the right to purchase natural gas from the Corporation at a specified price in future periods in exchange for an upfront cash payment to Perpetual;
- entering into fixed price contract for natural gas production; and
- entering into contracts to fix the basis differential between natural gas markets.

If product prices increase above the levels specified in Perpetual's various hedging agreements, the Corporation would be precluded from receiving the full benefit of commodity price increases.

In addition, by entering into these hedging activities the Corporation may suffer financial loss if:

- Perpetual is unable to produce sufficient quantities of natural gas to fulfill its obligations;
- Perpetual is required to pay a margin call on a financial hedge contract; or
- Perpetual is required to pay royalties based on a market or reference price that is higher than its hedged fixed or ceiling price.

Renegotiation or termination of contracts

As at the date hereof, the Corporation does not anticipate that any aspect of its business will be materially affected in the current fiscal year by the renegotiation or termination of contracts or subcontracts.

Environmental considerations

Compliance with health, safety and environmental laws and regulations could materially increase the Corporation's costs. Perpetual will incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. These include costs to reduce certain types of air emissions and discharges and to remediate contamination at various facilities and third party sites where the Corporation's products or wastes will be handled or disposed.

Perpetual is subject to statutory strict liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of the Corporation's licenses. As a result, anyone who suffers losses or damages as a result of pollution caused by Perpetual's operations can claim compensation without needing to demonstrate that the damage is due to any fault on the Corporation's part.

New laws and regulations, tougher requirements in licensing, increasingly strict enforcement of, or new interpretations of, existing laws and regulations and the discovery of previously unknown contamination may require future expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups; or
- curtail or cease certain operations.

In addition, increasingly strict environmental requirements may affect product specifications and operational practices. Future expenditures to meet such specifications could have a material adverse effect on the Corporation's operations or financial condition. Any abandonment costs Perpetual incurs will reduce cash available for dividends to Shareholders and other uses.

The Corporation is proactive in its approach to environmental concerns. Procedures are in place to ensure that due care is taken in the day-to-day management of its properties. All government regulations and procedures are followed in adherence to the law. The Corporation believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to the Corporation.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to our future performance. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "outlook", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for natural gas and oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and hedging to be employed, and the value of financial forward natural gas, oil and other risk management contracts; funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; operating, G&A, and other expenses; cash dividends, and the funding and tax treatment thereof; the costs and timing of future abandonment and reclamation, asset retirement and environmental obligations; the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporations's asset base; expected costs relating to the Corporation's gas storage project; anticipated future capacity of the Corporation's gas storage facility; the timing of receipt of escrowed funds; the Corporation's acquisition strategy and the existence of acquisition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom; Perpetual's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets; expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value; funds flow; ability to fund dividends and exploration and development; our corporate strategy; expectations regarding Perpetual's access to capital to fund its acquisition, exploration and development activities; the transition to IFRS and its impact on the Corporation's financial results; expected realization of gas over bitumen royalty adjustments; future income tax and its effect on funds flow and dividends; intentions with respect to preservation of tax pools of and taxes payable by the Corporation; funding of and anticipated results from capital expenditure programs; renewal of and borrowing costs associated with the credit facility; future debt levels, financial capacity, liquidity and capital resources; future contractual commitments; drilling, completion, facilities and construction plans, and the effect thereof; the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers; Crown royalty rates; Perpetual's treatment under governmental regulatory regimes; business strategies and plans of management, including future changes in the structure of business operations; and the reliance on third parties in the industry to develop and expand Perpetual's assets and operations.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Corporation including, without limitation, that Perpetual will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of Perpetual to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of Perpetual's reserve and resource volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the timing and costs of storage facility and pipeline construction and expansion and the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and funds flow to fund the Corporation's capital and operating requirements as needed; and the extent of Perpetual's liabilities.

The Corporation believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: volatility in market prices for oil and natural gas products; supply and demand regarding the Perpetual's products; risks inherent in Perpetual's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems; unanticipated operating events that can reduce production or cause production to be shut-in or delayed; changes in exploration or development plans by Perpetual or by third party operators of Perpetual's properties; reliance on industry partners; uncertainties or inaccuracies associated with estimating reserves volumes; competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance; increased costs; incorrect assessments of the value of acquisitions; increased debt levels or debt service requirements; industry conditions including fluctuations in the price of natural gas and related commodities; royalties payable in respect of Perpetual's production; governmental regulation of the oil and gas industry, including environmental regulation; fluctuation in foreign exchange or interest rates; the need to obtain required approvals from regulatory authorities; changes in laws applicable to the Corporation, royalty rates, or other regulatory matters; general economic conditions in Canada, the United States and globally; stock market volatility and market valuations; limited, unfavourable, or a lack of access to capital markets, and certain other risks detailed from time to time in Perpetual's public disclosure documents. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Corporation or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws.

Additional information on Perpetual, including the most recent filed Annual Report and Annual Information Form, can be accessed at www.sedar.com or from the Corporation's website at www.perpetualenergyinc.com.