

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") of financial conditions and results of operations should be read in conjunction with the audited consolidated financial statements and accompanying notes of Penn West Energy Trust ("Penn West", "the Trust", "we" or "our") for the years ended December 31, 2006 and 2005. The date of this MD&A is February 28, 2007.

For additional information, including the Trust's audited financial statements and Annual Information Form, go to the Trust's website at www.pennwest.com, in Canada at www.sedar.com or in the United States at www.sec.gov.

All dollar amounts contained in this MD&A are expressed in millions of Canadian dollars unless noted otherwise.

Please refer to our disclaimer on forward-looking statements at the end of this MD&A. The calculations of barrels of oil equivalent ("boe") are based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of crude oil. This could be misleading if used in isolation as it is based on an energy equivalency conversion method at the burner tip and does not necessarily represent a value equivalency at the wellhead.

Measures including cash flow, cash flow per unit-basic, cash flow per unit-diluted, netbacks and distributable cash from operations included in this MD&A are not defined in generally accepted accounting principles ("GAAP"); accordingly, they may not be comparable to similar measures provided by other issuers. Management utilizes cash flow, and netbacks to assess financial performance, to allocate its capital among alternative projects and to assess our capacity to fund distributions and future capital programs.

Calculation of Cash Flow

(\$ millions, except per unit amounts)	Three months ended December 31		Year ended December 31	
	2006	2005	2006	2005
Cash flow from operating activities	\$ 261.1	\$ 368.7	\$ 1,106.3	\$ 932.8
Increase (decrease) in non-cash working capital	32.9	(42.4)	43.6	1.8
Payments for surrendered options	–	–	–	141.6
Asset retirement expenditures	9.3	6.3	26.9	22.6
Realized foreign exchange gain	–	–	–	85.8
Cash flow	\$ 303.3	\$ 332.6	\$ 1,176.8	\$ 1,184.6
Basic per unit	\$ 1.23	\$ 2.03	\$ 5.86	\$ 7.28
Diluted per unit	\$ 1.22	\$ 2.03	\$ 5.78	\$ 7.14

Quarterly Financial Summary

(\$ millions, except per unit and production amounts)

Three months ended	Penn West Energy Trust							Penn West Petroleum Ltd.
	Dec. 31 2006	Sept. 30 2006	June 30 2006	Mar. 31 2006	Dec. 31 2005	Sept. 30 2005	June 30 2005	Mar. 31 2005
Gross revenues	\$ 578.5	\$ 636.0	\$ 452.5	\$ 433.9	\$ 554.5	\$ 535.0	\$ 424.2	\$ 405.3
Cash flow	303.3	365.6	264.7	243.2	332.6	334.9	257.0	260.1
Basic per unit ⁽¹⁾	1.23	1.55	1.59	1.49	2.03	2.06	1.58	1.61
Diluted per unit ⁽¹⁾	1.22	1.53	1.56	1.47	2.03	2.04	1.49	1.58
Net income	122.9	177.8	220.5	144.4	241.1	209.5	59.7	66.9
Basic per unit ⁽¹⁾	0.44	0.66	1.34	0.88	1.48	1.29	0.37	0.41
Diluted per unit ⁽¹⁾	0.44	0.65	1.31	0.87	1.46	1.27	0.34	0.41
Distributions declared	241.5	240.7	167.6	162.0	151.8	127.3	42.4	–
Per unit	1.02	1.02	1.02	0.99	0.93	0.78	0.26	–
Dividends declared	–	–	–	–	–	–	–	10.8
Per unit ⁽¹⁾	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –	\$ 0.07
Production								
Liquids ⁽²⁾ (bbls/day)	70,819	69,215	48,599	52,226	51,953	51,634	50,633	53,162
Natural gas (mmcf/day)	354.6	359.1	267.9	266.9	277.5	289.0	295.7	289.1
Total (boe/day)	129,915	129,059	93,242	96,713	98,205	99,802	99,910	101,343

(1) Per unit figures for the periods prior to June 30, 2005 have been restated to reflect the conversion of Penn West common shares to trust units using an exchange ratio of three trust units per share in accordance with the plan of arrangement dated May 31, 2005 related to the trust conversion.

(2) Includes crude oil and natural gas liquids.

Petrofund Merger

As of June 30, 2006, all approvals required to close the merger of Penn West and Petrofund Energy Trust ("Petrofund") had been received and the merger was completed effective June 30, 2006. Petrofund unitholders received 0.6 of a Penn West unit for each Petrofund unit exchanged and also received a special distribution of \$1.00 per unit plus an adjustment of \$0.10 per unit required to align the distribution dates of the trusts.

Penn West accounted for the Petrofund merger as a purchase of Petrofund. The consolidated financial statements of Penn West include the results of operations and cash flows of Petrofund from July 1, 2006 forward. If the merger had occurred on January 1, 2006, Penn West would have realized the following pro forma results for the year ended December 31, 2006:

(\$ millions, except per unit amounts)

Revenue	\$ 2,496.5
Net income	722.9
Basic per unit	3.07
Diluted per unit	\$ 3.03
Production (boe/day)	132,373

Business Environment

The current business environment has moderate commodity prices, accessible capital markets, low interest rates by historical standards and a relatively stable regulatory environment other than the October 31, 2006 Government of Canada announcement of proposed changes to the taxation of income trusts.

Continuing demand for crude oil from growing economies such as China and India, along with political instability in parts of the world, resulted in stronger oil prices in 2006. The price of West Texas Intermediate ("WTI"), the primary benchmark for light crude oil prices, averaged US\$66.22 per barrel in 2006, up by 17 percent from 2005.

Heavy oil differentials narrowed in 2006 as asphalt and residual fuel markets' demand exceeded the normal seasonal demand early in 2006. The price was also supported by industry initiatives to improve access into U.S. heavy oil markets. The Canadian Bow River differential to WTI narrowed by 10 percent from 2005.

AECO natural gas prices weakened in 2006, decreasing by 26 percent to \$6.53 per mcf from \$8.81 per mcf in 2005. Warm 2005 and early 2006 winters in North America resulted in lower demand and higher storage levels that led to lower prices.

Lower natural gas prices and a strengthening of the Canadian dollar relative to the U.S. dollar more than offset the benefit of stronger oil prices. Oil sales contracts are generally based on WTI prices denominated in U.S. dollars; therefore the strengthening Canadian dollar reduces Canadian dollar realization. The average exchange rate increased from CAD\$1.00 equals USD\$0.825 in 2005 to CAD\$1.00 equals USD\$0.882 in 2006. In early 2007, the Canadian dollar has weakened to approximately CAD\$1.00 equals USD\$0.85.

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Regulations and incentive programs governing the calculation of royalties have been stable in recent years; however, there can be no assurance they will not change in the future.

High levels of industry activity increased operating costs in 2006 due to increases in the demand for energy, steel, services and other costs over 2005. However, Penn West is encouraged that its fourth quarter 2006 operating costs per barrel of oil equivalent remained approximately level with the third quarter of 2006. The flat operating cost per barrel of oil equivalent was achieved by our initiatives to contain operating cost increases and by realizing approximately \$17 million in gains on electricity hedges.

We have a proven management team, dedicated employees and a business plan appropriate for an energy trust. Over the last 15 years, we progressed from a small explorer and producer to the top ranks of independent oil and natural gas producers in Western Canada. In 2005, we converted into the largest conventional oil and natural gas trust by production in Canada and added to production and reserves through the Petrofund merger in 2006. We have a disciplined approach to business that stresses cost control and product balance. Using this discipline, we have shown that we can explore for and develop grassroots reserves, and also successfully acquire and optimize producing fields. We have a diverse asset base in the Western Canada Sedimentary Basin divided into three core areas ranging from southern Manitoba to regions bordering the Northwest Territories.

Our goal is to create and protect unitholder value by:

- Pursuing an active program of internal development, focusing on low-risk opportunities to maintain production or reduce operating costs, and on resource plays such as the Peace River Oil Sands project and our portfolio of CO₂ enhanced oil recovery projects;
- Participating in exploration, without the requirement to fund capital expenditures, through the farm-out of undeveloped lands;

- Rationalizing our asset base with the aim of maintaining distributions over the long-term, including asset acquisitions and dispositions that are accretive or strategic; and
- Maintaining a strong balance sheet.

Proposed Tax on Income Trusts

On October 31, 2006, the Government of Canada announced proposed changes to the taxation of publicly traded income trusts. Commencing in 2011, taxes at estimated corporate tax rates were proposed on distributions that represent a return on capital by disallowing these distributions as a deduction in the calculation of the trust's taxable income. Subsequent to the October 31 announcement, the Government of Canada tabled draft legislation and clarified the rules related to "undue expansion". Recently, hearings of the House of Commons' finance committee have been held; however, it is not yet clear what impact, if any, the hearings will have on the proposed tax. If the tax proposals are enacted into law as proposed on October 31, 2006, they could have some or all of the following impacts, and Penn West could take some or all of the following actions:

- If structural or other similar changes are not made, the after-tax distribution yield in 2011 to taxable Canadian investors will remain approximately the same, however, the distribution yield in 2011 to tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) and foreign investors will fall by an estimated 31.5 percent and 26.5 percent, respectively;
- A portion of Penn West's cash flow could be allocated to the payment of cash distribution taxes, or other forms of tax, and will not be available for distribution or re-investment;
- It could be determined that it is more economic for Penn West to change to a corporate structure to facilitate investing a higher proportion or all of its cash flow in exploration and development projects. Such a conversion and change to capital programs would result in a significant reduction or elimination of distributions and/or dividends;
- It could be determined that it is more economic to remain in the trust structure and pay corporate income taxes rather than the proposed distribution tax and pay all or a portion of our distributions on a return of capital basis at a potentially significantly lower payout ratio;
- Other strategic alternatives could be determined to be more economic than any of the above; and/or
- If income trusts are subsequently determined to be taxable entities for future income tax accounting purposes, the recording of an additional future income tax liability would be required and the change in the future income tax liability could be material.

The table below, provided by the Government of Canada in a backgrounder accompanying its October 31, 2006 announcement, shows a simplified comparison of the effects of the proposed changes to investor tax rates in 2011:

Investor	Current System		Proposed System	
	Income Portion of Trust Distributions	Large Corporation (dividend)	Income Portion of Trust Distributions	Large Corporation (dividend)
Taxable Canadian individuals ⁽¹⁾	46%	46%	45.5%	45.5%
Canadian tax-exempt investors	0%	32%	31.5%	31.5%
Taxable U.S. investors ⁽²⁾	15%	42%	41.5%	41.5%

(1) All rates in the table are as of 2011, and include both entity- and investor-level tax (as applicable). Rates for "taxable Canadian individuals" assume that top personal income tax rates apply and that provincial governments increase their dividend tax credit for dividends of large corporations.

(2) Canadian taxes only. U.S. tax will also apply in most cases, net of any foreign tax credits.

Our Board of Directors and management team are reviewing the impact, if any, of the proposals on our business strategy.

Unitholder Value Measures

	Year ended December 31		
	2006	2005	2004
Cash flow per unit (\$)	5.86	7.28	5.37
Distributions per unit (\$)	4.05	1.97	–
Dividends per unit (\$)	–	0.07	0.16
Ratio of year-end bank debt to annual cash flow	1.1	0.5	0.6

We have a strong in-house professional and technical staff, an extensive base of undeveloped land (3.7 million net acres at year-end 2006) and a strong balance sheet. These attributes provide us the ability to pursue strategies of organic growth through development and optimization, growth through strategic or accretive acquisitions and the farm-out of undeveloped land. We believe in the application of financial discipline in all areas of operations as a key factor in achieving superior returns on investment for our unitholders.

Performance Indicators

	Year ended December 31		
	2006	2005	2004
Return on capital employed ⁽¹⁾	12.8%	17.0%	9.0%
Total assets (\$ millions)	8,070	3,967	3,867
Return on equity ⁽²⁾	18.1%	28.3%	15.3%

⁽¹⁾ Net income before financing charges divided by average total liabilities less current assets.

⁽²⁾ Net income divided by average unitholders' equity.

Results of Operations

Production

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Daily Production						
Natural gas (mmcf/day)	354.6	277.5	28	312.5	287.8	9
Light oil and NGL (bbls/day)	48,233	33,227	45	39,514	33,137	19
Conventional heavy oil (bbls/day)	22,586	18,726	21	20,776	18,705	11
Total production (boe/day) ⁽¹⁾	129,915	98,205	32	112,369	99,807	13

⁽¹⁾ Barrels of oil equivalent (boe) are based on six mcf of natural gas being equal to one barrel of oil (6:1).

The increase in production was generally due to the Petrofund merger closing at the end of June 2006, and to our development and optimization programs.

We strive to maintain an approximately balanced portfolio of liquids and natural gas production provided it is economic to do so. We believe a balance by product helps to reduce exposure to price volatility that can affect a single commodity. Crude oil and NGL production averaged 70,819 barrels per day (55 percent of production) in the fourth quarter of 2006 and natural gas production averaged 354.6 mmcf per day (45 percent of production) in the same quarter.

We invested \$159.4 million on capital expenditures and drilled 52 net wells in the fourth quarter of 2006. Drilling activity was focused in the Central and Plains areas.

Commodity Markets

Natural Gas

Natural gas prices declined throughout 2006, from close to record highs at the end of the prior year, due to a warm winter in 2005-2006 that weakened demand and resulted in higher than normal storage levels. Spot natural gas prices at AECO in the fourth quarter of 2006 increased by \$1.18 per mcf or 21 percent from the prior quarter to average \$6.91 per mcf while decreasing by \$4.70 per mcf or 40 percent from the fourth quarter of 2005. AECO gas prices of \$6.53 per mcf in 2006 decreased by 26 percent from \$8.81 per mcf for the prior year.

Crude Oil

International crude oil prices remained strong with the benchmark West Texas Intermediate price averaging US\$59.96 per barrel in the fourth quarter of 2006. However, this was a decrease of US\$10.52 per barrel from the prior quarter. Oil prices had reached near-record highs in 2006 with continued high demand for crude oil and refined products and political instability in the Middle East. The Edmonton par price for light sweet crude oil remained strong year-over-year, slightly under performing WTI, due to a well-supplied crude oil market in Canada and the strengthening of the Canadian dollar relative to the U.S. dollar.

Average Sales Prices Received

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Natural gas (\$/mcf)	\$ 6.97	\$ 11.66	(40)	\$ 6.75	\$ 8.68	(22)
Risk management (\$/mcf)	0.56	–	–	0.72	0.06	1,100
Natural gas net (\$/mcf)	7.53	11.66	(35)	7.47	8.74	(15)
Light oil and liquids (\$/bbl)	57.43	64.28	(11)	65.02	62.59	4
Risk management (\$/bbl)	0.01	–	–	(1.00)	–	–
Light oil and liquids net (\$/bbl)	57.44	64.28	(11)	64.02	62.59	2
Conventional heavy oil (\$/bbl)	37.57	34.95	7	43.07	35.71	21
Weighted average (\$/boe)	46.88	61.38	(24)	49.58	52.50	(6)
Risk management (\$/boe)	1.53	–	–	1.64	0.18	811
Weighted average net (\$/boe)	\$ 48.41	\$ 61.38	(21)	\$ 51.22	\$ 52.68	(3)

Operating Netbacks

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Natural gas						
Production (mmcf/day)	354.6	277.5	28	312.5	287.8	9
Operating netback (\$/mcf):						
Sales price	\$ 6.97	\$ 11.66	(40)	\$ 6.75	\$ 8.68	(22)
Hedging gain	0.56	–	–	0.72	0.06	1,100
Royalties	1.61	2.67	(40)	1.51	1.86	(19)
Operating costs	1.04	0.87	20	0.99	0.85	16
Transportation	0.18	0.22	(18)	0.21	0.21	–
Netback	\$ 4.70	\$ 7.90	(41)	\$ 4.76	\$ 5.82	(18)
Light oil and NGL						
Production (bbls/day)	48,233	33,227	45	39,514	33,137	19
Operating netback (\$/bb):						
Sales price	\$ 57.43	\$ 64.28	(11)	\$ 65.02	\$ 62.59	4
Hedging gain / (loss)	0.01	–	–	(1.00)	–	–
Royalties	10.21	11.46	(11)	10.51	10.17	3
Operating costs	15.36	15.17	1	15.80	14.43	9
Netback	\$ 31.87	\$ 37.65	(15)	\$ 37.71	\$ 37.99	(1)
Conventional heavy oil						
Production (bbls/day)	22,586	18,726	21	20,776	18,705	11
Operating netback (\$/bb):						
Sales price	\$ 37.57	\$ 34.95	7	\$ 43.07	\$ 35.71	21
Royalties	5.44	5.67	(4)	6.51	5.41	20
Operating costs	11.88	9.64	23	11.22	9.30	21
Transportation	0.07	0.10	(30)	0.07	0.09	(22)
Netback	\$ 20.18	\$ 19.54	3	\$ 25.27	\$ 20.91	21
Total liquids						
Production (bbls/day)	70,819	51,953	36	60,290	51,842	16
Operating netback (\$/bb):						
Sales price	\$ 51.09	\$ 53.71	(5)	\$ 57.46	\$ 52.89	9
Hedging gain / (loss)	0.01	–	–	(0.66)	–	–
Royalties	8.69	9.38	(7)	9.13	8.45	8
Operating costs	14.25	13.18	8	14.22	12.58	13
Transportation	0.02	0.04	(50)	0.03	0.03	–
Netback	\$ 28.14	\$ 31.11	(10)	\$ 33.42	\$ 31.83	5
Combined totals						
Production ⁽¹⁾ (boe/day)	129,915	98,205	32	112,369	99,807	13
Operating netback (\$/boe):						
Sales price	\$ 46.88	\$ 61.38	(24)	\$ 49.58	\$ 52.50	(6)
Hedging gain	1.53	–	–	1.64	0.18	811
Royalties	9.12	12.52	(27)	9.10	9.74	(7)
Operating costs	10.61	9.44	12	10.39	8.99	16
Transportation	0.51	0.64	(20)	0.60	0.62	(3)
Netback	\$ 28.17	\$ 38.78	(27)	\$ 31.13	\$ 33.33	(7)

(1) Boe or barrels of oil equivalent are based on six mcf of natural gas being equal to one barrel of oil (6:1).

Production Revenues

Revenues from the sale of crude oil, NGL and natural gas consisted of the following:

(\$ millions)	Year ended December 31		
	2006	2005	2004
Natural gas	\$ 850.9	\$ 918.2	\$ 773.0
Light oil and NGL	923.4	757.0	537.7
Conventional heavy oil	326.6	243.8	210.6
Total	\$ 2,100.9	\$ 1,919.0	\$ 1,521.3

The increase in revenue resulted from higher volumes due to the Petrofund merger and higher oil prices, partially offset by lower natural gas prices.

Increases (Decreases) in Production Revenues

(\$ millions)	
Gross revenues – 2005	\$ 1,919.0
Increase in light oil and NGL production	145.7
Increase in light oil and NGL prices (including realized hedging activities)	20.7
Increase in conventional heavy oil production	27.0
Increase in conventional heavy oil prices	55.8
Increase in natural gas production	78.8
Decrease in natural gas prices (including realized hedging activities)	(146.1)
Gross revenues – 2006	\$ 2,100.9

Royalties

(\$ millions)	Year ended December 31		
	2006	2005	2004
Royalties (\$ millions)	\$ 373.3	\$ 355.0	\$ 296.1
Average royalty rate (%)	18%	19%	20%
\$/boe	\$ 9.10	\$ 9.74	\$ 7.65

Royalties, as a percentage of revenue, decreased in the quarter due to realized hedging gains. The Petrofund properties have higher average royalty rates than the Penn West properties, however, realized hedging gains reduced 2006 royalty rates compared to 2005.

Expenses

(\$ millions)	Year ended December 31		
	2006	2005	2004
Operating	\$ 426.3	\$ 327.4	\$ 300.4
Transportation	24.5	22.7	25.6
Financing	49.3	23.2	17.0
Equity-based compensation	\$ 11.3	\$ 77.2	\$ 84.1

(\$/boe)	Year ended December 31		
	2006	2005	2004
Operating	\$ 10.39	\$ 8.99	\$ 7.75
Transportation	0.60	0.62	0.66
Financing	1.20	0.63	0.45
Equity-based compensation	\$ 0.27	\$ 2.12	\$ 2.17

Operating

High levels of industry activity, in response to relatively high commodity prices, resulted in strong demand for oilfield services and labour that continued to put upward pressure on operating costs in 2006. In addition, higher energy costs translated into higher utility, chemical and trucking costs. A higher proportion of liquids production, combined with base production declines and interruptions, also contributed to higher per unit operating costs in 2006 than in 2005. The addition of the Petrofund assets with higher operating costs than Penn West's properties also contributed to the increase.

During 2006, as natural gas prices fell from their close to record highs, some significant oil and natural gas companies cut their capital programs, helping to reduce demand for oilfield services. This, combined with internal initiatives targeted at reducing operating costs, resulted in the operating cost per barrel of oil equivalent in the fourth quarter of 2006 being approximately equal to the rate for the third quarter of 2006.

Financing

We use short-term money market instruments to realize lower interest rates at the shorter end of the yield curve. The short end of the yield curve has increased due to rate increases by the central banks in Canada and the United States. The 2006 increase in interest expense was due to both an increase in the average outstanding debt balance and the increases in short-term interest rates over 2005. The average prime interest rate increased to 6.0 percent in the fourth quarter of 2006 from an average of 4.8 percent in the same quarter of 2005.

Interest and other financing costs for the year ended December 31, 2006 increased to \$49.3 million from \$23.2 million in 2005. The increased average loan balance was principally due to the \$610 million of debt assumed with the Petrofund merger.

Equity-Based Compensation

On the close of the trust conversion on May 31, 2005, Penn West implemented a trust unit rights incentive plan. Compensation expense related to this plan is based on the fair value of trust unit rights issued, determined using the Binomial Lattice option-pricing model. The fair value of rights issued is expensed on a straight-line basis over the vesting periods of the rights. Prior to the trust conversion, the Trust's predecessor company, Penn West Petroleum Ltd. ("the Company"), had a stock option plan with a cash settlement alternative; as a result, equity-based compensation was recorded based on changes in the intrinsic value of stock options.

General and Administrative Expenses

(\$ millions, except per boe amounts)	Year ended December 31		
	2006	2005	2004
Gross	\$ 62.0	\$ 45.0	\$ 41.3
Per boe	1.51	1.24	1.07
Net	36.0	23.1	16.1
Per boe	\$ 0.88	\$ 0.64	\$ 0.42

Increases in total and per boe general and administrative costs in 2006 were due to higher staff levels following the Petrofund merger and higher compensation costs. The cost of hiring, compensating and retaining employees and consultants remains high due to strong demand for staff, particularly those with specialized training and experience. Increasing costs related to regulatory compliance also contributed to the increase.

Taxes

(\$ millions)	Year ended December 31		
	2006	2005	2004
Capital	\$ 14.7	\$ 14.7	\$ 10.1
Current income	–	54.1	17.8
Future income (recovery)	(106.2)	(1.1)	109.6
	\$ (91.5)	\$ 67.7	\$ 137.5

Capital taxes recorded in 2006 were consistent with 2005 as higher revenues subject to the Saskatchewan resource surcharge, were offset by the enactment of the elimination of the Canadian federal large corporations tax and reductions to the rate of the Saskatchewan resource surcharge.

In the second quarter of 2006, Penn West recorded a \$74 million future income tax recovery to reflect corporate tax rate reductions substantively enacted by the federal, Alberta and Saskatchewan governments.

Under our current structure, the operating entities make interest and royalty payments to the Trust, which transfers taxable income to the Trust to eliminate income subject to corporate and other income taxes in the operating entities. Under the terms of its trust indenture, the Trust is required to distribute amounts equal to at least its taxable income. In the event that the Trust has undistributed taxable income in a taxation year, an additional special taxable distribution, subject to certain withholding taxes, would be required by the terms of its trust indenture.

If the proposed distribution tax is enacted and Penn West's structure is not changed, Penn West will become a taxable entity, and from 2011 and subsequent future income tax recoveries will likely not be recorded for income transfers to the trust.

Tax Pools

(\$ millions)	As at December 31		
	2006	2005	2004
Undepreciated capital cost (UCC)	\$ 788.3	\$ 519.0	\$ 276.4
Canadian oil and gas property expense (COGPE)	1,091.0	707.6	611.5
Canadian development expense (CDE)	428.8	329.8	95.4
Canadian exploration expense (CEE)	—	—	—
Non-capital losses	106.1	—	—
Total tax pools	\$ 2,414.2	\$ 1,556.4	\$ 983.3

The significant increase in the 2006 tax pools reflects the merger with Petrofund. The tax pool figures are net of income deferred in operating partnerships.

Depletion, Depreciation and Accretion ("DD&A")

(\$ millions, except per boe amounts)	Year ended December 31		
	2006	2005	2004
Depletion of oil and natural gas assets ⁽¹⁾	\$ 623.7	\$ 406.1	\$ 383.7
Gas plant depreciation	11.3	10.4	10.6
Accretion of asset retirement obligation ⁽²⁾	19.7	21.1	18.8
Total DD&A	654.7	437.6	413.1
DD&A expense per boe	\$ 15.96	\$ 12.01	\$ 10.67

(1) Includes depletion of the capitalized portion of the asset retirement obligation.

(2) Represents the accretion expense on the asset retirement obligation during the period.

Higher DD&A expense in 2006 versus 2005 was due to the Petrofund merger. The merger was accounted for as a purchase with the purchase price allocated to the net assets acquired. The purchase allocation to oil and natural gas assets significantly increased our consolidated depletion base and therefore increased our DD&A rate.

Foreign Exchange

In 2006, we had no U.S.-dollar-denominated debt. In 2005, the Company realized a foreign exchange gain of \$85.8 million on the conversion of U.S.-dollar-denominated debt to Canadian-dollar debt.

Cash Flow and Net Income

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Cash flow (\$ millions)	\$ 303.3	\$ 332.6	(9)	\$ 1,176.8	\$ 1,184.6	(1)
Basic per unit	1.23	2.03	(39)	5.86	7.28	(20)
Diluted per unit	1.22	2.03	(40)	5.78	7.14	(19)
Net income (\$ millions)	122.9	241.1	(49)	665.6	577.2	15
Basic per unit	0.44	1.48	(70)	3.32	3.55	(6)
Diluted per unit	\$ 0.44	\$ 1.46	(70)	\$ 3.27	\$ 3.48	(6)

Cash flow realized in 2006 decreased from 2005 due to lower natural gas prices offset by higher production and higher oil prices.

Net income increased from 2005 levels due to higher production following the Petrofund merger and future income tax recoveries offset by lower natural gas prices. The lower fourth quarter 2006 net income reflects higher depletion, depreciation and accretion charges following the Petrofund merger.

	Year ended December 31					
	2006		2005		2004	
	\$/boe	%	\$/boe	%	\$/boe	%
Oil and natural gas revenues	\$ 51.22	100.0	\$ 52.68	100.0	\$ 39.29	100.0
Net royalties	(9.10)	(17.8)	(9.74)	(18.5)	(7.65)	(19.5)
Operating expenses	(10.39)	(20.3)	(8.99)	(17.1)	(7.75)	(19.7)
Transportation	(0.60)	(1.2)	(0.62)	(1.1)	(0.66)	(1.7)
Net operating income	31.13	60.7	33.33	63.3	23.23	59.1
General and administrative expenses	(0.88)	(1.7)	(0.64)	(1.2)	(0.42)	(1.1)
Interest	(1.20)	(2.3)	(0.63)	(1.2)	(0.45)	(1.1)
Realized foreign exchange gain	–	–	2.35	4.4	0.74	1.9
Current and capital taxes	(0.36)	(0.7)	(1.89)	(3.6)	(0.71)	(1.8)
Cash flow	28.69	56.0	32.52	61.7	22.39	57.0
Unrealized foreign exchange gain (loss)	–	–	(2.48)	(4.7)	0.30	0.8
Equity-based compensation	(0.27)	(0.5)	(2.12)	(4.0)	(2.17)	(5.5)
Risk management activities	1.18	2.3	(0.09)	(0.2)	–	–
Depletion, depreciation and accretion	(15.96)	(31.2)	(12.01)	(22.8)	(10.67)	(27.2)
Future income taxes	2.59	5.1	0.03	–	(2.83)	(7.2)
Net income	\$ 16.23	31.7	\$ 15.85	30.0	\$ 7.02	17.9

Capital Expenditures

(\$ millions)	Three months ended December 31		Year ended December 31	
	2006	2005	2006	2005
Property acquisitions (dispositions), net	\$ 10.9	\$ (91.3)	\$ 5.6	\$ (5.8)
Land acquisition and retention	0.8	3.7	19.8	13.5
Drilling and completions	86.1	61.0	317.4	277.1
Facilities and well equipping	57.9	30.0	224.6	155.2
Geological and geophysical	1.0	0.8	3.6	7.4
CO ₂ pilot costs	1.1	1.9	3.7	8.1
Administrative	1.6	0.2	3.2	1.2
Capital expenditures	159.4	6.3	577.9	456.7
Petrofund merger	–	–	3,323.3	–
Total expenditures	\$ 159.4	\$ 6.3	\$ 3,901.2	\$ 456.7

We drilled 52 net wells in the fourth quarter of 2006, resulting in 12 net natural gas wells and 38 net oil wells with a success rate of 96 percent. Our drilling activities were focused in the Central and Plains areas. For 2006 we drilled 270 net wells, 105 net natural gas and 149 net oil wells with a success rate of 94 percent.

CO₂ pilot costs represent capital expenditures related to the Pembina CO₂ pilot project, including the cost of injectants, for which no reserves have been booked.

On June 30, 2006, we merged with Petrofund. The fair value of the oil and gas properties acquired of \$3.3 billion was added to property, plant and equipment and the remaining \$0.7 billion of the purchase price was attributed to goodwill. Goodwill was recorded to reflect that we increased our production capacity to levels which made us the largest conventional oil and gas royalty trust in North America, that we increased our exposure to light oil giving us a better future product balance as we increase our future production from the Peace River Oil Sands, and that we increased our reserve life index and technological access to, and staff with experience in, resource plays including the Weyburn CO₂ project and coalbed methane.

Our farm-out program is ongoing; since 2005 to year-end 2006, 272 wells have been drilled on Penn West's lands, including re-completions and re-entries, by independent operators that incur drilling, completions and other capital costs on these properties. In the fourth quarter of 2006, 57 wells were drilled on our lands, bringing the total to 169 wells for 2006.

In addition to the above capital expenditures, \$1.7 million was capitalized in relation to future income taxes on minor acquisitions in the Swan Hills area, with less tax basis than the purchase price, and \$55.9 million was capitalized from additions to and revisions of asset retirement obligations.

Business Risks

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Market Risk Management

We are exposed to normal market risks inherent in the oil and natural gas business, including commodity price risk, credit risk, interest rate risk and foreign currency risk. From time to time, we attempt to minimize exposure to a portion of these risks using financial instruments.

Commodity Price Risk

We have substantial exposure to commodity price fluctuations. Crude oil prices are influenced by worldwide factors such as OPEC actions, supply and demand fundamentals, and political events. Oil prices, North American natural gas supply and demand factors and storage levels influence natural gas prices. Pursuant to our policies, we may, from time to time, manage these risks through the use of costless collars or other financial instruments up to a maximum of 50 percent of forecast sales volumes, net of royalties, for a two-year period or up to 75 percent of forecast sales volumes, net of royalties, for a one-year period.

For a current summary of outstanding oil and natural gas hedging contracts, please refer to our website at www.pennwest.com.

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. All of our receivables are with customers in the oil and natural gas industry and are subject to normal industry credit risk. In order to limit the risk of non-performance of counterparties to derivative instruments, we contract only with organizations with high credit ratings or by obtaining security in certain circumstances.

Interest Rate Risk

We maintain our debt in floating-rate bank facilities, resulting in exposure to fluctuations in short-term interest rates. From time to time, we may increase the certainty of future interest rates using financial instruments to swap floating interest rates for fixed rates or to collar interest rates. In 2006, we entered into interest rate swaps that fix the interest rate for two years at 4.36 percent on \$100 million of bank debt.

Foreign Currency Rate Risk

Prices received for sales of crude oil are referenced to, or denominated in, U.S. dollars, and thus realized oil prices may be impacted by Canadian to United States exchange rates. When we consider it appropriate, we may use financial instruments to fix or collar future exchange rates. At December 31, 2006, we had no financial instruments outstanding related to foreign exchange rates.

Liquidity and Capital Resources

Capitalization

	Year ended December 31					
	2006		2005		2004	
	(\$ millions)	%	(\$ millions)	%	(\$ millions)	%
Trust units issued, at market	\$ 8,435	86.0	\$ 6,203	90.5	\$ 4,269	86.0
Bank loan – long-term	1,285	13.1	542	7.9	503	10.2
Working capital deficiency ⁽¹⁾	86	0.9	127	1.6	190	3.8
Total enterprise value	\$ 9,806	100.0	\$ 6,872	100.0	\$ 4,962	100.0

(1) Current assets minus current liabilities.

On June 30, 2006, we issued approximately 70.7 million trust units on the close of the Petrofund merger. During 2006, 2.5 million units were issued in lieu of cash under the Distribution Re-investment and Optional Purchase Plan, 0.4 million units were issued on the exercise of rights under the Trust Unit Rights Incentive Plan and 0.3 million units were issued to match employee contributions under the Trust Unit Savings Plan.

During 2006, we paid distributions of \$781.8 million compared to distributions of \$270.9 million and dividends of \$17.5 million in 2005. This reflects that we were a trust for the full year in 2006, we paid higher per unit distributions in 2006 and we issued additional units on the Petrofund merger.

Under the terms of its current trust indenture, the Trust is required to make distributions to unitholders in amounts at least equal to its taxable income. Distributions may be monthly or special and in cash or in trust units at the discretion of our Board of Directors. To the extent that additional cash distributions are paid and capital programs are not adjusted, debt levels may increase. In the event that a special distribution in the form of trust units is declared, the terms of the trust indenture require that the outstanding units be consolidated immediately subsequent to the distribution. The number of outstanding trust units would remain at the number outstanding immediately prior to the unit distribution, less those sold to fund the payment of withholding taxes, and an amount equal to the distribution would be allocated to the unitholders as a taxable distribution.

Our philosophy is to retire approximately 10 percent of our opening asset retirement obligation annually, using our cash flow. Due to the extent of our environmental programs, we believe no benefit would arise from the initiation of a reclamation fund. We believe our program is sufficient to meet or exceed existing environmental regulations and best industry practices. In the event of significant changes to the environmental regulations or the cost of environmental activities, a higher portion of cash flow would be required to fund our environmental expenditures.

Bank debt at December 31, 2006 was \$1,285 million compared to \$542 million at December 31, 2005. In the third quarter of 2006, our wholly owned subsidiary, Penn West Petroleum Ltd., amended its unsecured, extendible, three-year revolving syndicated credit facility. The amended credit facility has an aggregate borrowing limit of \$1.8 billion plus a \$100 million swing line facility with stamping fees ranging from 60-115 basis points and standby fees ranging from 12.5-22.5 basis points depending on our ratio of consolidated bank debt to earnings before interest, taxes and depreciation and depletion ("EBITDA"). During 2006, the Company extended the facility termination date to August 25, 2009. As at December 31, 2006, there was \$515 million (December 31, 2005 – \$628 million) available under the syndicated credit facility to finance future activities.

During 2006, the Company secured a \$650 million bridge facility and utilized it to retire Petrofund's bank debt of \$610 million on the close of the merger. The bridge facility was re-paid from the proceeds of the re-syndication of the credit facility on August 25, 2006. On December 31, 2006, the Company was in compliance with all of the financial covenants under the credit facility. The financial covenants under the new syndicated credit facility are as follows:

- Consolidated bank debt to EBITDA shall be less than 3:1 except in certain circumstances and shall not exceed 3.5:1;
- Consolidated total debt to EBITDA shall be less than 4:1; and
- Consolidated bank debt to total trust capitalization shall not exceed 50 percent except in certain circumstances and shall not exceed 55 percent.

Reconciliation of Cash Flow from Operating Activities to Distributable Cash from Operations

Penn West has elected to voluntarily present the following reconciliation of distributable cash from operations based on guidance contained in the Canadian Institute of Chartered Accountants' related November 2006 draft interpretive release. In the draft release, sustainability concepts are discussed and distributable cash from operations is defined as cash flow from operating activities less adjustments for productive capacity maintenance, long-term unfunded contractual obligations and the effect of any foreseeable financing matters, related to debt covenants, which could impair our ability to pay distributions.

(\$ millions, except per unit amounts)	Three months ended December 31		Year ended December 31	
	2006	2005	2006	2005 ⁽¹⁾
Cash flow from operating activities	\$ 261.1	\$ 368.7	\$ 1,106.3	\$ 696.5
Productive capacity maintenance ⁽²⁾	(148.5)	(97.6)	(572.3)	(212.1)
Distributable cash from operations	112.6	271.1	534.0	484.4
Proceeds from the issue of trust units ⁽³⁾	31.3	2.4	118.6	8.3
Bank borrowings and working capital changes	97.6	(121.7)	159.2	(171.2)
Cash distributions declared	\$ 241.5	\$ 151.8	\$ 811.8	\$ 321.5
Accumulated cash distributions, beginning	891.8	169.7	321.5	—
Accumulated cash distributions, ending	\$ 1,133.3	\$ 321.5	\$ 1,133.3	\$ 321.5
Distributable cash from operations per unit, basic	0.48	1.66	2.66	2.98
Distributable cash from operations per unit, diluted	0.47	1.63	2.62	2.92
Distributable cash payout ratio ⁽⁴⁾	2.14	0.56	1.52	0.66
Distributions declared per unit	\$ 1.02	\$ 0.93	\$ 4.05	\$ 1.97
Distributions declared as a percentage of net income	197%	63%	122%	56%
Distributions declared as a percentage of cash flow	80%	46%	69%	43%

(1) Includes the operations of Penn West subsequent to the effective date of the Trust conversion, May 31, 2005.

(2) Please refer to our discussion of productive capacity maintenance below.

(3) Consists of proceeds from the Distribution Reinvestment and Optional Purchase Plan, the Trust Unit Rights Incentive Plan and the Trust Unit Savings Plan.

(4) Represents cash distributions declared divided by distributable cash from operations.

We strive to fund both distributions and capital programs from cash flow. We budget our capital programs at approximately 40-50 percent of forecast cash flow. We believe that proceeds from the Distribution Re-investment and Optional Purchase Plan should be used to fund capital expenditures of a longer-term nature. Over the medium term, additional borrowings and equity issues may be required from time to time to fund a portion of our distributions or maintain or increase our productive capacity. On a longer-term basis, adjustments to the level of distributions and/or capital expenditures to maintain or increase our productive capacity may be required based on forecast levels of distributable cash from operations and capital efficiency.

Productive capacity maintenance is generally the amount required in a period for an enterprise to maintain its ability to generate future cash flow from operating activities at a constant level. As commodity prices can be volatile, we define our productive capacity as production on a barrel of oil equivalent basis. Short-term variations in production levels are often experienced in our business. A quantifiable measure for these short-term variations is not objectively quantifiable or verifiable due to various factors including the inability to distinguish natural production declines from the effect of production additions from capital and optimization programs, and the effect of temporary production interruptions. As a result, the adjustment for productive capacity maintenance in our calculation of distributable cash from operations is our actual capital expenditures during the period excluding the cost of any acquisitions or proceeds of any dispositions. We believe that our current capital programs will be sufficient to maintain our productive capacity in the medium-term and set our hurdle rates for evaluating potential development and optimization projects accordingly.

Our calculation of distributable cash from operations has no adjustment for long-term unfunded contractual obligations. We believe our only significant long-term unfunded contractual obligation at this time is for asset retirement obligations. Cash flow from operating activities, used in our distributable cash from operations calculation, includes a deduction for actual abandonment expenditures during the period. We believe that our philosophy, to retire approximately 10 percent of our opening asset retirement obligation on an annual basis, is sufficient to fund our asset retirement obligations over the life of our reserves.

We currently have no financing restrictions caused by our debt covenants. We regularly monitor our current and forecast debt levels to ensure debt covenants are not exceeded.

(\$ millions, except indicators)	As at December 31, 2006
Cumulative distributable cash from operations ⁽¹⁾	\$ 1,018.4
Issue of trust units	126.9
Bank borrowing and working capital change	(12.0)
Cumulative cash distributions declared ⁽¹⁾	\$ 1,133.3
Distributable cash payout ratio ⁽²⁾	1.11

⁽¹⁾ Subsequent to the trust conversion on May 31, 2005.

⁽²⁾ Represents cumulative cash distributions paid divided by cumulative distributable cash from operations.

Financial Instruments

We currently have WTI crude oil collars on approximately 26,000 barrels per day from January 1 to December 31, 2007 and 10,000 barrels per day from January 2008 to June 2008. The collars on the 26,000 barrels per day to December 2007 have an average floor price of US\$56.12 per barrel and an average ceiling price of US\$83.50 per barrel. The 2008 WTI crude oil collars have an average floor price of US\$60.00 per barrel and an average ceiling price of US\$94.55 per barrel. In addition, Penn West has AECO natural gas collars on approximately 76 mmcf per day from January 1 to October 31, 2007 with an average floor price of \$7.69 per mcf and an average ceiling price of \$9.79 per mcf.

In the second quarter of 2006, we entered into interest rate swaps that fix the interest rate for two years at approximately 4.36 percent on \$100 million of bank debt.

Other financial instruments outstanding at December 31, 2006 are Alberta electricity contracts, which fix electricity costs on 67 megawatts at \$49.55 per megawatt hour and 2 megawatts at \$57.00 per megawatt hour.

Mark to market amounts on all financial instruments outstanding on December 31, 2006 are summarized in note 12 to the audited consolidated financial statements. Please refer to Penn West's website at www.pennwest.com for details of financial instruments currently outstanding.

Outlook

The outlook for oil and natural gas prices remains strong compared to historical levels. For 2007, we initially budgeted net capital expenditures of \$550 million to \$650 million, to fund the drilling of 220-250 net wells. Estimated average 2007 production was forecast between 130,000 boe per day and 132,000 boe per day. Based on a forecast WTI oil price of US\$59.00 per barrel, a \$7.25 per mcf natural gas price at AECO and an exchange rate of CAD\$1.00 equals US\$0.86 for 2007, cash flow for 2007 was forecast to be between \$1.1 billion and \$1.4 billion.

Subsequent to the completion of our 2007 budget, our board of directors approved the \$339 million property acquisition announced in February 2007 and an increase to the budgeted capital program in the Peace River Oil Sands project to \$175 million from \$100 million.

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on 2007 financial results before considering hedging impacts, the property acquisition announced on February 9, 2007 and the expanded capital program in the Peace River Oil Sands, are outlined in the table below.

(\$ millions, except per unit amounts)	Change	Impact on Cash Flow ⁽¹⁾		Impact on Net Income ⁽¹⁾	
		\$ millions	\$/unit	\$ millions	\$/unit
Change of					
Price per barrel of liquids	\$ 1.00	22.8	0.10	15.7	0.07
Liquids production	1,000 bbls/day	16.9	0.07	9.3	0.04
Price per mcf of natural gas	\$ 0.10	9.7	0.04	6.7	0.03
Natural gas production	10 mmcf/day	23.1	0.10	12.0	0.05
Effective interest rate	1%	13.5	0.06	9.3	0.04
Exchange rate (US\$ per CAD\$)	\$ 0.01	29.4	0.12	20.3	0.09

⁽¹⁾ The impact on cash flow and net income is computed based on 2007 forecast commodity prices and production volumes. The impact on net income assumes that the distribution levels are not adjusted for changes in cash flow thus changing the incremental tax rate.

Contractual Obligations and Commitments

We are committed to certain payments over the next five calendar years as follows:

(\$ millions)	2007	2008	2009	2010	2011	Thereafter
Transportation	\$ 20.0	\$ 9.2	\$ 4.7	\$ 1.9	\$ –	\$ –
Transportation (US\$)	2.5	2.3	2.3	2.3	2.3	8.6
Power infrastructure	4.6	3.7	3.7	3.7	3.7	7.6
Drilling rigs	6.9	7.7	2.4	1.2	–	–
Purchase obligations ⁽¹⁾	13.2	13.3	13.3	13.3	13.3	54.3
Office lease	\$ 12.0	\$ 17.9	\$ 17.5	\$ 15.1	\$ 14.3	\$ 117.5

⁽¹⁾ These amounts represent estimated commitments of \$95.5 million for CO₂ purchases and \$25.2 million for processing fees related to interests in the Weyburn Unit.

On February 9, 2007, Penn West announced we had entered into an agreement to acquire conventional oil and natural gas assets. The transaction is expected to close in March 2007 subject to the satisfaction of certain conditions, including the rights of first refusal held on certain assets by working interest parties and the receipt of regulatory approvals. The purchase price of the asset package, prior to any reductions due to rights of first refusal, totals approximately \$339 million before closing adjustments of an estimated \$12 million, which will reduce the cash outlays on closing.

Our credit facility expires in approximately three years, and if we were not successful in renewing it or replacing it, we would be required to repay all amounts then outstanding on the facilities in August 2009. As we maintain our leverage ratios at relatively modest levels, we believe we will be successful in renewing or replacing our credit facilities on acceptable terms.

Equity Instruments

Trust units issued:	
As at December 31, 2006	237,126,219
Issued on exercise of trust unit rights	9,590
Issued to employee savings plan	74,770
Issued pursuant to distribution re-investment plan	450,095
As at February 28, 2007	237,660,674
Trust unit rights outstanding:	
As at December 31, 2006	11,284,872
Granted	3,713,469
Exercised	(9,590)
Forfeited	(218,100)
As at February 28, 2007	14,770,651

Disclosure Controls and Procedures

We have established a Disclosure Committee that is responsible for ensuring that our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us is recorded, processed, summarized and reported within the time periods specified under Canadian securities laws, and that our controls and procedures are designed to ensure that information is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, to allow timely decisions regarding required disclosure. Our Disclosure Committee includes selected members of senior management, including the Chief Executive Officer, the Chief Operating Officer and the Chief Financial Officer.

As at December 31, 2006, an evaluation was carried out, under the supervision of the Disclosure Committee and with the participation of management, of the effectiveness of our disclosure controls and procedures as defined under the Multilateral Instrument 52-109. As at December 31, 2006, the design and operating effectiveness of our disclosure controls and procedures were assessed by our Chief Executive Officer and Chief Financial Officer to be operating effectively.

Internal Controls Over Financial Reporting

We have assembled a team of qualified and experienced staff and consultants who have been working on compliance with the applicable regulations regarding internal controls over financial reporting. As we are listed in both Canada and the United States, the recent changes in Canada to remove the requirement for auditor attestation and to extend the timing of CEO/CFO certification of the effective operation of internal controls over financial reporting to 2008 will not affect us.

We became a registrant of the U.S. Securities and Exchange Commission and listed on the New York Stock Exchange in June 2006. As a 2006 applicant, we are not required to certify or obtain auditor attestation of the operating effectiveness of our internal controls over financial reporting until we file our 2007 year-end audited financial statements. To date, all significant financial reporting processes have been documented and the resulting changes in internal control over financial reporting are substantially completed. Based on this work to date, no changes were made to our internal controls over financial reporting during the quarter ended December 31, 2006 that materially affected, or would be reasonably likely to materially affect, our internal controls over financial reporting.

Accounting Changes and Pronouncements

Financial Instruments, Other Comprehensive Income

This pronouncement, effective for fiscal year-ends on or after October 1, 2006, addresses when to recognize, and how to measure, a financial instrument on the balance sheet and how gains and losses are to be presented. An additional financial statement, other comprehensive income, is required in certain circumstances. We currently have no items that would create other comprehensive income. The fair value of financial instruments, which are designated as hedges, are to be included on the balance sheet as a financial asset or liability with the related mark-to-market gain or loss recognized in other comprehensive income.

Financial instruments, not designated as hedges, will be valued at market with any related gains and losses recognized in income of the period. As we elected to account for all of our derivative financial instruments using the fair value method on July 1, 2005, this required change will have no effect on our reported financial position or net income or loss.

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Non-Monetary Transactions

Effective January 1, 2006, this accounting pronouncement requires that non-monetary transactions be measured at fair value unless certain conditions apply. This pronouncement did not impact our reported results.

Related-Party Transactions

In 2006, we paid \$4.1 million (2005 – \$2.1 million) of legal fees to a law firm of which a partner is also one of our directors.

Off-Balance-Sheet Financing

We have off-balance-sheet financing arrangements consisting of operating leases. The details of the operating lease payments are summarized in the Contractual Obligations and Commitments section.

Critical Accounting Estimates

Our significant accounting policies are detailed in note 2 to the audited consolidated financial statements. In the determination of financial results, we must make certain significant accounting estimates as follows:

Full Cost Accounting

We use the full cost method of accounting for oil and natural gas properties. All costs of exploring for and developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved reserves with forecast commodity pricing.

Our reserves were evaluated by GLJ Petroleum Consultants Ltd., an independent engineering firm. In both 2006 and 2005, our reserves were determined in compliance with National Instrument 51-101. The evaluation of oil and natural gas reserves is, by its nature, based on complex extrapolations and models as well as other significant engineering, capital, pricing and cost assumptions. Reserve estimates are a key component in the calculation of depletion and are a key component of value in the ceiling test. To the extent that the ceiling amount, based in part on our reserves, is less than the carrying amount of property, plant and equipment, a write-down against income must be made. We determined there was no ceiling test write-down required at December 31, 2006.

Asset Retirement Obligations

The discounted, expected future cost of statutory, contractual or legal obligations to retire long-lived assets is recorded as an asset retirement liability with a corresponding increase to the carrying amount of the related asset. The recorded liability increases over time to its future liability amount through accretion charges to earnings, included in DD&A. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to our asset retirement obligation. Actual asset retirement expenditures are charged to the liability to the extent of the then-recorded liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset. Note 7 to the audited consolidated financial statements details the impact of these accounting recommendations.

Financial Instruments

Financial instruments included in the balance sheets consist of accounts and taxes receivable, the fair value of the derivative financial instruments, current liabilities and the bank loan. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments, the mark to market values recorded for the financial instruments and the market rate of interest applied to the bank loan.

All of our accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. We may, from time to time, use various types of financial instruments to reduce our exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these financial instruments exposes us to credit risks associated with the possible non-performance of counterparties to the derivative contracts. We limit this risk by transacting only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

Our revenues from the sale of crude oil, natural gas liquids and natural gas are directly impacted by changes to the underlying commodity prices. To ensure that cash flows are sufficient to fund planned capital programs and distributions, costless collars or other financial instruments may be utilized. Collars ensure that commodity prices realized will fall into a contracted range for a contracted sales volume. Forward power contracts fix a portion of future electricity costs at levels determined to be economic by management.

Goodwill

Goodwill must be recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, it must be assessed for impairment at least annually. Impairment is initially determined based on the fair value of the reporting entity compared to its book value. Any impairment must be charged to income or loss in the period the impairment occurs. We determined there was no goodwill impairment as at December 31, 2006.

Forward-Looking Statements

In the interest of providing Penn West's unitholders and potential investors with information regarding Penn West, including management's assessment of Penn West's future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and can be profitably produced in the future. In particular, this document contains forward-looking statements pertaining to, without limitation, the following: the nature of the proposed changes to the taxation of income trusts in Canada, the effects of the proposed changes to investor tax rates in 2011, the impact on our business of the proposed tax changes and the different actions that we might take in response to the proposed tax changes; the stability and growth potential of our asset base; our intention to focus our efforts on our Peace River Oil Sands project and expand the project more rapidly in the future, including the estimated number of wells to be drilled in 2007, estimated 2007 capital expenditures levels and the anticipated nature of those expenditures, our intention to complete the installation of pipeline infrastructure to the main project development area, the daily production target by the end of 2007 and within four years for this project, and the recovery methods anticipated to be employed to attain these targets; our current estimate of the amount of heavy oil resources in place in our Peace River Oil Sands project area and our belief that the potential production and reserve additions for this project could be very significant; our intention to continue to add oil, natural gas and electricity hedges; the estimated amount of light oil resources in place in the Pembina field, the amount of such resources that have been recovered to date and the potential to recover additional significant light oil reserves; our intention to expand our Pembina carbon dioxide pilot project to apply horizontal well technology in order to accelerate the production response and thus improve the capital payout timelines; the anticipated timing for the commercial start-up of the Pembina CO₂ project; our belief that we can demonstrate an economic, environmentally proactive approach to enhancing recovery from mature, light conventional oil fields and developing our non-conventional oil resources; the amount anticipated to be spent on environmental programs in 2007 and the long-term benefits to be derived therefrom by unitholders; our near-term and long-term business strategies (including risk management strategies) and plans of management, including our intention in 2007 to maintain production volumes, improve capital efficiencies, and continue our efforts toward the realization of the significant and long-term benefits the Peace River Oil Sands project and the CO₂ Enhanced Recovery projects could provide; our ability to explore for and develop grassroots reserves, and also successfully acquire and optimize producing fields; our intention to create and protect unitholder value by (i) pursuing an active program of internal development (and the focus of such development), (ii) participating in exploration through the farm-out of undeveloped lands, (iii) rationalizing our asset base, and (iv) maintaining a strong balance sheet; our ability to pursue strategies of organic growth through development and optimization, growth through strategic or accretive acquisitions and the farm-out of undeveloped land; our desire to maintain an approximately balanced portfolio of liquids and natural gas production; the existence, operation and strategy of our risk management program, including methods of managing market risks, commodity price risks, credit risks, interest rate risks and foreign currency risks; our intention to retire approximately 10 percent of our opening asset retirement obligation annually using our cash flow; the intended use of proceeds received under the Distribution Reinvestment and Optional Purchase Plan; the methods of funding distributions and maintaining or increasing our productive capacity over the medium and long-term; our belief that our current capital programs will be sufficient to maintain our barrel of oil equivalent productive capacity in the medium-term; our belief that our philosophy to retire approximately 10 percent of our opening asset retirement obligation on an annual basis is sufficient to fund our asset retirement obligations over the life of our reserves; our belief that our only significant long-term unfunded contractual obligation is for asset retirement obligations; our outlook for oil and natural gas prices; our forecast 2007 net capital expenditures and the number of wells to be drilled; our estimated average 2007 production forecast; our budget for oil prices, natural gas prices and the USD/CAD exchange rate for 2007; our forecast cash flow for 2007; the timing for closing the acquisition announced on February 9, 2007 and the purchase price therefor; our belief that we will be successful in

renewing or replacing our credit facilities on acceptable terms when it expires; and the quantity and recoverability of our oil and natural gas reserves and resources.

With respect to forward-looking statements contained in this document, we have made assumptions regarding, among other things: future oil and natural gas prices and differentials between light, medium and heavy oil prices; future oil and natural gas production levels; future exchange rates; the amount of future cash distributions that we intend to pay; the cost of expanding our property holdings; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; our ability to obtain all necessary approvals required to complete the acquisition announced on February 9, 2007 and to complete the acquisition when expected; and our ability to add production and reserves through our development and exploitation activities.

Although Penn West believes that the expectations reflected in the forward-looking statements contained in this document, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this document, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause Penn West's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility in market prices for oil and natural gas; the impact of weather conditions on seasonal demand and ability to execute capital programs; risks inherent in oil and gas operations; uncertainties associated with estimating reserves and resources; competition for, among other things, capital, acquisitions of reserves, resources, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; geological, technical, drilling and processing problems; general economic conditions in Canada, the U.S. and globally; industry conditions, including fluctuations in the price of oil and natural gas; royalties payable in respect of our oil and natural gas production; changes in government regulation of the oil and natural gas industry, including environmental regulation; fluctuations in foreign exchange or interest rates; unanticipated operating events that can reduce production or cause production to be shut-in or delayed; failure to obtain industry partner and other third-party consents and approvals when required; stock market volatility and market valuations; OPEC's ability to control production and balance global supply and demand of crude oil at desired price levels; political uncertainty, including the risks of hostilities, in the petroleum producing regions of the world; the need to obtain required approvals from regulatory authorities from time to time; failure to realize the anticipated benefits of acquisitions, including the merger with Petrofund Energy Trust; failure to obtain required approvals or otherwise complete the acquisition announced on February 9, 2007 on the expected timeline or at all; and the other factors described under "Business Risks" in this document and in Penn West's public filings (including our Annual Information Form) available in Canada at www.sedar.com and in the United States at www.sec.gov. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, Penn West does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Additional Information

Additional information relating to Penn West, including its Annual Information Form, is available on SEDAR at www.sedar.com.