U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

x Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2006

Commission file number 1-32895

PENN WEST ENERGY TRUST

(Exact name of registrant as specified in its charter)

Alberta, Canada	**1311**	**Not applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number (if applicable))	(I.R.S. Employer Identification Number (if Applicable))

Suite 2200, 425 1st Street S.W. Calgary, Alberta, Canada T2P 3L8
(403) 777-2666
(Address and Telephone Number of Registrant's Principal Executive Offices)

DL Services Inc., 1420 Fifth Avenue, Suite 3400, Seattle, WA 98101
(206) 903-5448
(Name, Address (Including Zip Code) and Telephone Number
(Including Area Code) of Agent For Service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	**Name of each exchange on which registered**
Trust Units	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

For annual reports, indicate by check mark the information filed with this Form:

x Annual Information Form x Audited Annual Financial Statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 237,126,219

Indicate by check mark whether the registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes o No x

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Principal Documents

The following documents, filed as Exhibits 99.1, 99.2, 99.3 and 99.4 to this Annual Report on Form 40-F, are hereby incorporated by reference into this Annual Report on Form 40-F:

(a) Annual Information Form for the fiscal year ended December 31, 2006;

(b) Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2006;

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2006; and

(d) Supplemental Note to the Consolidated Financial Statements relating to the reconciliation of Canadian and United States Generally Accepted Accounting Principles.

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.5 and 99.6 to this Annual Report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of Penn West Energy Trust's ("Penn West") fiscal year ended December 31, 2006, an evaluation of the effectiveness of Penn West's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the management of Penn West Petroleum Ltd., the administrator of Penn West, with the participation of the President and Chief Executive Officer ("CEO") and the Senior Vice President and Chief Financial Officer ("CFO") of Penn West Petroleum Ltd., who also perform such functions for Penn West. Based upon that evaluation, the CEO and CFO have concluded that as of the end of that fiscal year, Penn West's disclosure controls and procedures are effective to ensure that information required to be disclosed by Penn West in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to Penn West's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while the CEO and CFO believe that Penn West's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that Penn West's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2006, there were no changes in Penn West's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Penn West's internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

Penn West's board of directors has determined that James C. Smith, a member of Penn West's audit committee, qualifies as an "audit committee financial expert" (as such term

is defined in Form 40-F). Mr. Smith is "independent" as that term in defined in the rules of the New York Stock Exchange.

Code of Business Conduct.

Penn West has adopted a Code of Ethics for Officers and Senior Financial Management. Penn West has also adopted a Code of Business Conduct and Ethics that applies to all employees, officers and directors of Penn West. These Codes constitute a "code of ethics" as defined in Form 40-F.

The Code of Ethics for Officers and Senior Financial Management and the Code of Business Conduct and Ethics are each available for viewing on Penn West's website at www.pennwest.com, and are available in print to any unitholder who requests a copy of them. Requests for copies of either of the Codes should be made by contacting: investor relations by phone at (888) 770-2633 or by e-mail to investor_relations@pennwest.com.

Since the adoption of the Code of Ethics for Officers and Senior Financial Management and the Code of Business Conduct and Ethics, respectively, there have not been any amendments to, or waivers, including implicit waivers, from, any provision of the Codes.

Principal Accountant Fees and Services.

The following table sets forth information about the fees billed to Penn West for professional services provided by KPMG LLP during fiscal 2006 and 2005:

(CDN$)	2006	2005
Audit Fees	$ 485,000	$ 215,000
Audit-Related Fees	230,000	187,500
Tax Fees	18,341	42,738
All Other Fees	—	—
Total	$ 733,341	$ 445,238

Fees. Audit fees consist of fees for the audit of Penn West's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of Penn West's financial statements and are not reported as Audit Fees. During fiscal 2006 and 2005, the services provided in this category included due diligence reviews in connection with acquisitions and corporate reorganizations, Sarbanes-Oxley related services and French translation services.

Tax Fees. Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2006 and 2005, the services provided in this category included

assistance and advice in relation to the communication of the taxability of distributions to unitholders and the preparation of corporate income tax returns.

All Other Fees. None.

Pre-Approval Policies and Procedures.

(a) The terms of the engagement of Penn West's external auditors to provide audit services, including the budgeted fees for such audit services and the representations and disclaimers relating thereto, must be pre-approved by the entire audit committee.

With respect to any engagements of Penn West's external auditors for non-audit services, Penn West must obtain the approval of the audit committee or the Chairman of the audit committee prior to retaining the external auditors to complete such engagement. If such pre-approval is provided by the Chairman of the audit committee, the Chairman shall report to the audit committee on any non-audit service engagement pre-approved by him at the audit committee's first scheduled meeting following such pre-approval.

If, after using its reasonable best efforts, Penn West is unable to contact the Chairman of the audit committee on a timely basis to obtain the pre-approval contemplated by the preceding paragraph, Penn West may obtain the required pre-approval from any other member of the audit committee, provided that any such audit committee member shall report to the audit committee on any non-audit service engagement pre-approved by him at the audit committee's first scheduled meeting following such pre-approval.

(b) Of the fees reported in this Annual Report on Form 40-F under the heading "Principal Accountant Fees and Services", none of the fees billed by KPMG LLP were approved by Penn West's audit committee pursuant to the *de minimus* exception provided by Section (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

Off-Balance Sheet Arrangements.

Penn West does not have any off-balance sheet financing arrangements that have, or are reasonably likely to have, a material effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Tabular Disclosure of Contractual Obligations.

(CDN$ millions)

		Payment due by period			
Contractual Obligations	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
Transportation	59.5	22.9	19.3	7.3	10.0
Power Infrastructure	27.0	4.6	7.4	7.4	7.6
Drilling rigs	18.2	6.9	10.1	1.2	—
Purchase obligations (1)	120.7	13.2	26.6	26.6	54.3
Office lease	194.3	12.0	35.4	29.4	117.5

Long term debt (2)(3)	1,285.0	—	—	—	1,285.0
Asset retirement obligations (4)	1,269.0	33.9	67.8	67.8	1,099.5
Total	**2,967.1**	**93.5**	**166.6**	**139.7**	**2,573.9**

(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.
(2) Approval to extend the revolving period must be obtained from the banking syndicate in three years. Penn West and its predecessor have successfully extended its credit facility on each renewal date since 1992.
(3) Interest payments have not been included since future debt levels and rates are not known at this time.
(4) These amounts represent the undiscounted future reclamation and abandonment costs that are expected to be incurred over the life of the properties.

Identification of the Audit Committee.

Penn West has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Thomas E. Phillips, James C. Smith, Murray R. Nunns, George H. Brookman and James E. Allard.

Disclosure Pursuant to the Requirements of the New York Stock Exchange.

Presiding Director at Meetings of Non-Management Directors

Penn West schedules regular executive sessions in which Penn West's "non-management directors" (as that term is defined in the rules of the New York Stock Exchange) meet without management participation. John A. Brussa serves as the presiding director (the "Presiding Director") at such sessions. Penn West's Board of Directors is responsible for determining whether or not each director is independent. In making this determination, the Board has adopted the definition of "independence" as set out in Section 1.4 of Multilateral Instrument 52-110 Audit Committees ("MI 52-110"). In applying this definition, the Board considers all relationships of the directors with Penn West, including business, family and other relationships. Penn West's Board of Directors also determines whether each member of Penn West's Audit Committee is independent pursuant to Sections 1.4 and 1.5 of MI 52-110 and Rule 10A-3 of the *Securities Exchange Act* of 1934. Penn West's Board of Directors has not adopted the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual.

Communication with Non-Management Directors

Unitholders may send communications to Penn West's non-management directors by writing to George H. Brookman care of Investor Relations – Penn West Energy Trust, 2200, 425 – First Street SW, Calgary Alberta, T2P 3L8. Communications will be referred to the Presiding Director for appropriate action. The status of all outstanding concerns addressed to the Presiding Director will be reported to the board of directors as appropriate.

Corporate Governance Guidelines

In accordance with the rules of the New York Stock Exchange, Penn West has adopted corporate governance guidelines, entitled "Governance Guidelines", that are available for viewing on Penn West's website at www.pennwest.com and are available in print to any unitholder who requests a copy of them. Requests for copies of the Governance Guidelines should be made by contacting: investor relations by phone (888) 770-2633 or by e-mail to investor_relations@pennwest.com.

Board Committee Mandates

The Mandates of Penn West's audit committee, human resources and compensation committee, governance committee, reserves committee and health, safety and environment committee are each available for viewing on Penn West's website at www.pennwest.com, and are available in print to any unitholder who requests them. Requests for copies of these documents should be made by contacting: investor relations by phone (888) 770-2633 or by e-mail to investor_relations@pennwest.com.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking.

Penn West undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Securities and Exchange Commission (the "Commission") staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process.

Penn West has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of Penn West shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

Pursuant to the requirements of the Exchange Act, Penn West certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 26, 2007.

PENN WEST ENERGY TRUST
By: Penn West Petroleum Ltd., its administrator

By: /s/ William E. Andrew
Name: William E. Andrew
Title: President and Chief Executive Officer

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the fiscal year ended December 31, 2006
99.2	Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2006
99.3	Consolidated Financial Statements for the fiscal year ended December 31, 2006
99.4	Supplemental Note to the Consolidated Financial Statements relating to the reconciliation of Canadian and United States Generally Accepted Accounting Principles
99.5	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.6	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.7	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.8	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.9	Consent of KPMG LLP
99.10	Consent of GLJ Petroleum Consultants Ltd.

Exhibit 99.1

PENN WEST ENERGY TRUST

2006 Annual Information Form

March 22, 2007

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APPENDICES:

"A" — REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION
"B" — GLJ REPORT ON RESERVES DATA
"C" — AUDIT COMMITTEE MANDATE

GLOSSARY OF TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board of Directors means the Board of Directors of Penn West Petroleum Ltd.

Penn West, **we**, **us, our** or **Trust** means Penn West Energy Trust and all its controlled entities on a consolidated basis.

Penn West Partnership means Penn West Petroleum, a general partnership, between Penn West Petroleum Ltd. and Trocana Resources Inc., a wholly owned subsidiary of Penn West Petroleum Ltd.

Trustee means CIBC Mellon Trust Company, our trustee.

Unitholders means holders of our Trust Units.

Independent Engineering

GLJ means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

GLJ Report means the report prepared by GLJ dated February 28, 2007 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to certain of our oil and natural gas assets at December 31, 2006.

Securities

Notes means the unsecured subordinated promissory notes issued by Penn West Petroleum Ltd. and Petrofund Ventures Trust now held by the Trust.

NPI means the net profit interests in the petroleum substances owned by our wholly owned subsidiaries and trusts held by the Trust.

Trust Unit means a unit issued by us, each unit representing an equal undivided beneficial interest in our assets.

Agreements

Administration Agreement means the agreement dated May 31, 2005 between the Trustee and Penn West Petroleum Ltd. pursuant to which Penn West Petroleum Ltd. agrees to provide certain administrative and advisory services in connection with the Trust.

NPI Agreements means the net profits interest agreement dated May 31, 2005 between Penn West Petroleum Ltd. and the Trust, the net profit interest agreement dated November 8, 2005 between Penn West Petroleum Ltd. and the Trust and the net profits interest agreement dated November 8, 2005 between Petrofund Ventures Trust, one of our wholly owned trusts, and the Trust.

Trust Indenture means the amended and restated trust indenture between the Trustee and Penn West Petroleum Ltd., amended and restated as of June 30, 2006.

Others

Petrofund Merger means the plan of arrangement under the *Business Corporations Act* (Alberta) pursuant to which Penn West acquired Petrofund Energy Trust.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel or barrels	GJ	gigajoule
bbl/d	barrels per day	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Bcf	billion cubic feet
NGLs	natural gas liquids	Mcf/d	thousand cubic feet per day
MMboe	million barrels of oil equivalent	MMcf/d	million cubic feet per day
Mboe	thousand barrels of oil equivalent	m^3	cubic metres
boe/d	barrels of oil equivalent per day	MMbtu	million British Thermal Units

Other	
BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.
MM$	one million dollars

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	bbl	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “budget”, “plan”, “continue”, “estimate”, “expect”, “forecast”, “may”, “will”, “project”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe” and other similar expressions. These 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 statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements based on assumptions pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of our oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those results anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; and
- the other factors discussed under “Risk Factors”.

The actual results could differ materially from those results anticipated in these forward-looking statements, which are based on assumptions, including: the market prices for oil and natural gas; the continued availability of capital, acquisitions of reserves, undeveloped lands and skilled personnel; the continuation of the current tax and regulatory regime; and other assumptions contained in this Annual Information Form.

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 resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements.

Description of Cash Flow

This Annual Information Form refers to cash flow and cash flow from operations derived from cash flow from operating activities (before changes in non-cash working capital, expenditures on abandonment and reclamation costs and payments for surrendered stock options). Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles, (“GAAP”) and therefore it may not be comparable with the calculation of similar

measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

For more information, see “Management’s Discussion and Analysis” for the year ended December 31, 2006, which includes a reconciliation of “cash flow” to cash flow from operating activities which has been filed on SEDAR at www.sedar.com. Cash flow is cash flow from operating activities before changes in non cash working capital, expenditures on site reclamation and restoration and payments for surrendered stock options.

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on SEDAR at *www.sedar.com* (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at 2200, 425 — 1st Street S.W., Calgary, Alberta, T2P 3L8.

PENN WEST ENERGY TRUST

General

We are an open-end investment trust created on April 22, 2005 under the laws of the Province of Alberta pursuant to the Trust Indenture as amended and restated on June 30, 2006. At that time, CIBC Mellon Trust Company was appointed as trustee under the Trust Indenture for a three year period. The beneficiaries of the Trust are holders of the Trust Units. Our principal and head office is located at 2200, 425 — 1st Street S.W., Calgary, Alberta, T2P 3L8.

We commenced operations in our current structure on June 1, 2005 after the completion of a plan of arrangement under the *Business Corporations Act* (Alberta). Pursuant to this plan of arrangement, holders of common shares of Penn West Petroleum Ltd. received three (3) Trust Units for each one (1) of their common shares.

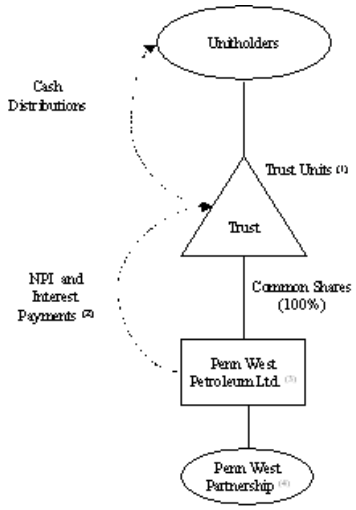
Inter-Corporate Relationships

The following are the names, the percentage of voting securities that we own and the jurisdiction of incorporation, continuance or formation of our material subsidiaries and partnerships either, direct or indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Penn West Petroleum Ltd.	100%	Corporation	Alberta
Penn West Petroleum	100%	General Partnership	Alberta

Our Organization Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries.



Notes:

(1) The Unitholders own 100 percent of the Trust's equity.

(2) Cash distributions are made on a monthly basis to Unitholders based upon our cash flow. Our primary sources of cash flow are payments from Penn West Petroleum Ltd. pursuant to the NPIs and interest on the principal amount of the Notes. In addition, we receive payments on one of the NPIs and interest on one of the Notes from Petrofund Ventures Trust.

(3) Penn West AcquisitionCo Inc., Penn West Petroleum Ltd., Penn West Exploration Ltd. and Northern Reef Exploration Ltd. were amalgamated as of January 1, 2006 under the name Penn West Petroleum Ltd.. Penn West was further amalgamated with Penn West (PTF) Energy Ltd. and Petrofund Alternative Energy Ltd. on January 1, 2007 under the name Penn West Petroleum Ltd.

(4) Penn West Petroleum Ltd. and Trocana Resources Inc. currently comprise the Penn West Partnership.

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

On May 31, 2005, Penn West Petroleum Ltd. completed a plan of arrangement whereby holders of common shares of Penn West Petroleum Ltd. received three (3) Trust Units for each one (1) of their common shares.

Effective June 30, 2006 Penn West completed the Petrofund Merger, pursuant to which Penn West acquired Petrofund Energy Trust on the basis of an exchange of .60 of a Trust Unit (an aggregate of 70.7 million Trust Units). A special cash distribution in the amount of $1.10 per unit (an aggregate of $129.6 million) of Petrofund Energy Trust, of which $0.10 per unit was to align the distribution record dates of the trusts, was made immediately prior to the completion of the Petrofund Merger to the holders of units of Petrofund Energy Trust. As a result of the acquisition pursuant to the Petrofund Merger, Penn West acquired 70.9 MMbbl of light/medium crude oil and NGLs, 0.7 MMbbl of heavy oil and 279.3 Bcf of natural gas on a proved reserve basis and 93.8 MMbbl of light/medium crude oil and NGLs, 1.0 MMbbl of heavy oil, 371.2 Bcf of natural gas on a proved plus probable reserve basis and 352,600 net acres of undeveloped land. Penn West assumed $610.4 million of bank indebtedness of Petrofund Energy Trust in connection with the Petrofund Merger.

For further information in relation to the Petrofund Merger, see note 3 of our consolidated financial statements for the year ended December 31, 2006, which is hereby incorporated by reference and which has been filed on SEDAR at www.sedar.com.

DESCRIPTION OF OUR BUSINESS

Overview

Our principal undertaking is to issue Trust Units and to acquire and hold securities of subsidiaries, trusts and partnerships, net profits interests, royalties, notes and other interests. Our direct and indirect subsidiaries and partnerships carry on the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and assets related thereto. A portion of the cash flow from the assets is paid from Penn West Petroleum Ltd. and Petrofund Ventures Trust to the Trust by way of interest and principal payments on the Notes and payments from Penn West Petroleum Ltd. and Petrofund Ventures Trust to the Trust under the NPI Agreements.

The Board of Directors may declare distributions payable to the Unitholders and allocate all or any of our income to the Unitholders. It is currently anticipated that the only income we will receive will be from Penn West Petroleum Ltd. and Petrofund Ventures Trust by way of interest received on the principal amount of Notes and payments pursuant to the NPI. We make monthly cash distributions to Unitholders from this income after any expenses and any cash redemptions of Trust Units.

Cash distributions are made on or about the 15th day of each month to Unitholders of record on or about the last calendar day of the immediately preceding month.

Penn West Petroleum Ltd.

Penn West Petroleum Ltd. is a corporation amalgamated and subsisting pursuant to the laws of Alberta. Penn West Petroleum Ltd. is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production in Canada. The Trust is the sole shareholder of Penn West Petroleum Ltd.

The registered and head office of Penn West Petroleum Ltd. is located at 2200, 425 — 1st Street S.W., Calgary, Alberta, T2P 3L8.

Notes

The Notes evidence the indebtedness of Penn West Petroleum Ltd. and Petrofund Ventures Trust to the Trust in connection with the plan of arrangement completed on May 31, 2005 and additional promissory notes acquired on the acquisition of Petrofund Energy Trust pursuant to the Petrofund Merger. The Notes from Penn West Petroleum Ltd. are unsecured and subordinated to senior indebtedness and bear interest at rates ranging from 11.25 percent to 13.00 percent per annum and require principal payments at dates ranging from May 31, 2017 to January 1, 2019. The Note from Petrofund Ventures Trust bears interest at a rate of six percent per annum and is payable on demand.

NPI

The Trust is a party to NPI Agreements with Penn West Petroleum Ltd. and Petrofund Ventures Trust pursuant to which we have the right to receive the NPIs on petroleum and natural gas rights held by Penn West Petroleum Ltd. and Petrofund Ventures Trust from time to time. Pursuant to the terms of the agreements, we are entitled to a payment from Penn West Petroleum Ltd. and Petrofund Ventures Trust for each month equal to the amount by which 99 percent of the gross proceeds from the sale of production attributable to the property interests of Penn West Petroleum Ltd. and Petrofund Ventures Trust for such month exceeds 99 percent of certain deductible costs for such period. Deductible costs generally include capital expenditures, royalties and operating costs related to oil and gas activities. The term of the agreement is for as long as there are petroleum and natural gas rights to which the NPIs apply.

Proposed Federal Tax Changes

On October 31, 2006 the Federal Minister of Finance proposed to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the unitholders (the “October 31 Proposals”). On December 21, 2006 the Federal Minister of Finance released draft legislation to implement the October 31 Proposals pursuant to which, commencing January 1, 2011 (provided Penn West only experiences “normal growth”

and no “undue expansion” before then) certain distributions from us which would have otherwise been taxed as ordinary income will be characterized as dividends to our Unitholders and will be subject to tax at corporate rates at the Trust level. Assuming the October 31 Proposals are ultimately enacted in their current form, the implementation of such legislation would be expected to result in adverse tax consequences to us and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada).

Management believes that the October 31 Proposals have reduced the market value of the Trust Units, which would be expected to increase the cost to Penn West of raising capital in the public capital markets. In addition, management believes that the October 31 Proposals are expected to: (a) substantially eliminate the competitive advantage that Penn West and other Canadian energy trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner; and (b) place Penn West and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The October 31 Proposals are also expected to make the Trust Units less attractive as consideration for acquisitions. As a result, it may become more difficult for us to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize our legal and tax structure to substantially mitigate the expected impact of the October 31 Proposals.

It is not known at this time when the October 31 Proposals will be enacted by Parliament, if at all, or whether the October 31 Proposals will be enacted in the form currently proposed or new proposals will be proposed or enacted. See “Risk Factors — Proposed Federal Tax Changes” and “Risk Factors — Changes in Legislation”.

STATEMENT OF RESERVES DATA

The Trust’s statement of reserves data and other oil and gas information is set forth below (the “Statement”). The effective date of the Statement is December 31, 2006 and the preparation date of the Statement is February 28, 2007. The Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3 and the Report on Reserves Data by GLJ on Form 51-102F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2006 contained in the GLJ Report dated February 28, 2007. The reserves data summarizes our oil, natural gas liquids and natural gas reserves and the net present values of future net revenue from these reserves using constant prices and costs and forecast prices and costs, not including the impact of any hedging activities. The reserves data conforms with the requirements of National Instrument 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves. See also “Definitions and Notes to Reserve Data Tables” below.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of crude

oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. For more information as to the risks involved, see “Risk Factors — Reserve Estimates” and “Risk Factors — Volatility of Oil and Natural Gas Prices”.

We are a taxable entity under the *Income Tax Act* (Canada) and, at the current time, are generally taxable only on income that is not distributed or distributable to Unitholders. As we currently distribute all our taxable income to Unitholders as required by the Trust Indenture, future net revenue after income taxes is not included in the disclosure tables. The proposed tax on income trust distributions, proposed by the Federal Finance Minister on October 31, 2006, has not been substantively enacted as income tax law. See “Risk Factors — Proposed Federal Tax Changes”.

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2006
CONSTANT PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	147,890	133,852	41,023	37,482
Developed Non-Producing	6,469	5,876	3,197	2,586
Undeveloped	33,706	29,773	1,841	1,533
TOTAL PROVED	188,066	169,500	46,062	41,600
PROBABLE	50,788	44,969	13,950	12,225

TOTAL PROVED PLUS PROBABLE	238,853	214,469	60,012	53,825

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	662,497	542,168	17,079	11,849
Developed Non-Producing	46,379	35,964	1,025	692
Undeveloped	43,028	35,060	1,469	1,019
TOTAL PROVED	751,904	613,191	19,573	13,560
PROBABLE	201,199	165,627	5,272	3,808
TOTAL PROVED PLUS PROBABLE	953,104	778,819	24,845	17,368

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	316,409	273,544
Developed Non-Producing	18,421	15,147
Undeveloped	44,188	38,168
TOTAL PROVED	379,018	326,859
PROBABLE	103,542	88,606
TOTAL PROVED PLUS PROBABLE	482,560	415,465

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED AT (%/year)
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED					
Producing	8,233	5,918	4,710	3,960	3,444
Developed Non-Producing	547	303	207	157	126
Undeveloped	1,328	741	462	304	207
TOTAL PROVED	10,108	6,961	5,378	4,421	3,776
PROBABLE	2,982	1,575	995	697	522
TOTAL PROVED PLUS PROBABLE	13,090	8,536	6,373	5,118	4,298

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	WELL ABANDONMENT COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)
Proved Reserves	19,795	2,595	6,130	666	296	10,108
Proved Plus Probable Reserves	25,121	3,333	7,411	982	305	13,090

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)
Proved Reserves	Light and Medium Crude Oil(1)	3,337
	Heavy Oil(1)	557
	Natural Gas(2)	1,484
TOTAL		5,378
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	3,910
	Heavy Oil(1)	687
	Natural Gas (2)	1,776
TOTAL		6,373

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2006
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	146,914	132,968	40,945	37,366
Developed Non-Producing	6,569	5,970	3,118	2,490
Undeveloped	33,447	29,672	1,839	1,525
TOTAL PROVED	186,929	168,611	45,902	41,381
PROBABLE	50,880	45,152	14,030	12,255
TOTAL PROVED PLUS PROBABLE	237,809	213,763	59,932	53,636

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	667,612	546,548	17,093	11,874
Developed Non-Producing	46,580	36,057	1,045	707
Undeveloped	43,433	35,445	1,452	1,009
TOTAL PROVED	757,625	618,049	19,590	13,589
PROBABLE	203,213	167,230	5,303	3,833
TOTAL PROVED PLUS PROBABLE	960,838	785,280	24,893	17,422

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	316,221	273,299
Developed Non-Producing	18,494	15,177
Undeveloped	43,977	38,113
TOTAL PROVED	378,692	326,589

PROBABLE	104,082	89,112
TOTAL PROVED PLUS PROBABLE	482,774	415,701

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED					
Developed Producing	9,369	6,568	5,174	4,333	3,762
Developed Non-Producing	742	375	248	186	149
Undeveloped	1,483	784	475	308	207
TOTAL PROVED	11,593	7,727	5,897	4,826	4,118
PROBABLE	3,847	1,891	1,152	793	588
TOTAL PROVED PLUS PROBABLE	15,440	9,618	7,049	5,619	4,706

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	WELL ABANDONMENT COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)
Proved Reserves	23,611	3,085	7,802	718	412	11,593
Proved Plus Probable Reserves	30,781	4,059	9,762	1,069	451	15,440

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)
Proved Reserves	Light and Medium Crude Oil (1)	3,319
	Heavy Oil(1)	588
	Natural Gas(2)	1,990
TOTAL		5,897
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	3,912
	Heavy Oil(1)	731
	Natural Gas(2)	2,406
TOTAL		7,049

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in “Disclosure of Reserves Data” and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. “**Gross**” means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) before deduction of royalties and without including any royalty interest of ours;

(b) in relation to wells, the total number of wells in which we have an interest; and

(c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) after deduction of royalty obligations, plus our royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we owned.

3. Columns may not add due to rounding.

4. The crude oil, natural gas liquids and natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). A summary of those definitions are set forth below:

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

5. **Forecast prices and costs**

These are prices and costs that are generally acceptable as being a reasonable outlook of the future. To the extent that there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs shall be incorporated into the forecast prices.

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, natural gas and natural gas liquids benchmark reference pricing, as at December 31, 2006, inflation and exchange rates utilized in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2006
FORECAST PRICES AND COSTS

	OIL					EDMONTON LIQUIDS PRICES				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40ºAPI ($Cdn/bbl)	Hardisty Heavy 12ºAPI ($Cdn/bbl)	Cromer Medium 29.3ºAPI ($Cdn/bbl)	NATURAL GAS AECO ($Cdn/Mcf)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	INFLATION RATES(1) %	EXCHANGE RATE(2) ($US equals $1 Cdn)
Forecast										
2007	62.00	70.25	39.25	61.25	7.20	45.00	50.25	71.25	2.0	0.870
2008	60.00	68.00	40.00	59.25	7.45	43.50	50.25	69.25	2.0	0.870
2009	58.00	65.75	39.75	57.25	7.75	42.00	48.75	67.00	2.0	0.870
2010	57.00	64.50	39.75	56.00	7.80	41.25	47.75	65.75	2.0	0.870
2011	57.00	64.50	40.25	56.00	7.85	41.25	47.75	65.75	2.0	0.870
2012	57.50	65.00	41.50	56.50	8.15	41.50	48.00	66.25	2.0	0.870
2013	58.50	66.25	42.50	57.75	8.30	42.50	49.00	67.50	2.0	0.870
2014	59.75	67.75	43.50	59.00	8.50	43.25	50.25	69.00	2.0	0.870
2015	61.00	69.00	44.25	60.00	8.70	44.25	51.00	70.50	2.0	0.870
2016	62.25	70.50	45.25	61.25	8.90	45.00	52.25	72.00	2.0	0.870
2017	63.50	71.75	46.00	62.50	9.10	46.00	53.00	73.25	2.0	0.870
Thereafter	+2%	+2%	+2%	+2%	+2%	+2%	+2%	+2%	2.0	0.870

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average actual prices realized, including hedging activities, for the year ended December 31, 2006 were $7.47/Mcf for natural gas, $65.32/bbl for light and medium crude oil, $43.07/bbl for heavy oil and $54.31/bbl for natural gas liquids.

6. **Constant prices and costs**

These are actual prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies. To the extent that there are fixed or presently determinable

future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs shall be incorporated into the price for future years.

The constant crude oil and natural gas benchmark reference pricing and the exchange rate utilized in the GLJ Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2006
CONSTANT PRICES AND COSTS

OIL				NATURAL GAS	EDMONTON LIQUID PRICES			EXCHANGE RATE(1)
WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	LLB Crude Oil at Hardisty ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	AECO ($Cdn/Mcf)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	($US equals $1 Cdn)
60.85	67.58	47.62	59.47	6.07	43.25	54.06	71.55	0.8581

Note:
(1) The exchange rate used to generate the benchmark reference prices in this table.

7. **Future Development Costs**

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	Forecast Prices and Costs		Constant Prices and Costs
Year	Proved Reserves (MM$)	Proved Plus Probable Reserves (MM$)	Proved Reserves (MM$)
2007	148	180	148
2008	166	213	162
2009	98	130	94
2010	73	99	69
2011	57	82	53
Total: Undiscounted for all years	718	1,069	666
Total: Discounted at 10%/year	518	732	497

We expect to fund the development costs of the reserves through a combination of cash flow withheld from distributions, debt, the sale of existing assets and the issuance of Trust Units.

There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to our reserves.

The interest and other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

8. Estimated future well abandonment costs related to reserve wells have been taken into account by GLJ in determining the aggregate future net revenue therefrom.

9. Both the constant and forecast price and cost assumptions assumed the continuance of current laws and regulations.

10. All factual data supplied to GLJ was accepted as represented. No field inspection was conducted.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

Reconciliations of Changes in Reserves and Future Net Revenue

The following table sets forth the reconciliation of our net reserves as at December 31, 2006, using forecast price and cost estimates derived from the GLJ Report.

RECONCILIATION OF
NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2005	122,380	25,864	148,244	45,177	11,556	56,733	462,790	109,805	572,595
Extensions	39	15	54	1,795	262	2,057	14,899	2,246	17,145
Improved Recovery(1)	3,106	4,156	7,262	553	248	801	8,767	1,468	10,235
Technical Revisions(2)	(3,268)	(2,137)	(5,405)	(334)	(49)	(383)	(4,901)	(12,174)	(17,075)

Discoveries	—	—	—	—	—	—	1,588	1,946	3,534
Acquisitions	56,751	17,173	73,924	612	234	846	223,120	64,201	287,321
Dispositions	(125)	(48)	(173)	(213)	(54)	(267)	(656)	(316)	(978)
Economic Factors	612	129	741	226	58	284	231	55	286
Production	(10,884)	—	(10,884)	(6,435)	—	(6,435)	(87,789)	—	(87,789)
December 31, 2006	168,611	45,152	213,763	41,381	12,255	53,636	618,049	167,231	785,280

Note:
(1) Improved recovery includes the following infill drilling:

Infill Drilling	1,328	50	1,377	489	269	758	5,720	720	6,440

FACTORS	NATURAL GAS LIQUIDS Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	TOTAL OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2005	9,560	1,990	11,550	254,249	57,711	311,960
Extensions	138	(27)	111	4,455	624	5,080
Improved Recovery(1)	170	46	216	5,290	4,695	9,985
Technical Revisions(2)	589	(80)	509	(3,830)	(4,295)	(8,124)
Discoveries	—	1	1	265	325	590
Acquisitions	4,298	1,905	6,203	98,848	30,012	128,859
Dispositions	(6)	(2)	(8)	(453)	(157)	(610)
Economic Factors	5	1	6	881	197	1,078
Production	1,165	—	(1,165)	(33,116)	—	(33,116)
December 31, 2006	13,589	3,834	17,422	326,589	89,113	415,701

Notes:
(1) Improved recovery includes the following infill drilling:

Infill Drilling	131	14	145	2,901	453	3,354

(2) Technical Revisions include reclassification of 1,558 Mbbl of proved oil reserves as heavy from light/medium and 1,692 Mbbl proved and probable oil reserves as heavy from light/medium.

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	2006 (MM$)
Estimated Future Net Revenue at Beginning of Year	4,972
Oil and Gas Sales During Period Net of Production Costs and Royalties(1)	(1,277)
Changes due to Prices and Royalties Related to Forecast Production(2)	(856)
Development Costs During the Period(3)	542
Changes in Forecast Development Costs(4)	(544)
Changes Resulting from Extensions and Improved Recovery(5)	164
Changes Resulting from Discoveries(5)	4
Changes Resulting from Acquisitions of Reserves(5)	1,907
Changes Resulting from Dispositions of Reserves(5)	(7)
Discount factor(6)	497
Net Change in Income Taxes(7)	—
Changes Resulting from Technical Reserves Revisions	(65)
All Other Changes(8)	41
Estimated Future Net Revenue at End of Year	5,378

Notes:

(1) Company actual before income taxes, excluding general and administrative expenses.
(2) The impact of changes in prices and other economic factors on future net revenue.
(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
(4) The change in forecast future development costs.
(5) End of period net present value of the related reserves.
(6) Estimated as 10 percent of the beginning of period net present value.
(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period. With conversion to a trust, Penn West Petroleum Ltd. does not pay income tax. See: "Other Oil and Gas Information — Tax Horizon" and "Risk Factors — Proposed Federal Tax Changes".
(8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates and actual prices received in 2006 versus forecast.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. Penn West plans to develop approximately one—half of the proved undeveloped reserves in the GLJ Report over the next two years and the significant majority of the proved undeveloped reserves over the next five years. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "Risk Factors".

Proved Undeveloped Reserves

GLJ has assigned 44 MMboe of proven undeveloped reserves in the GLJ Report under forecast prices and costs, together with $456 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first

two forecast years of the GLJ Report accounts for $202 million, or 44 percent, of the total forecast. These figures increase to $380 million or 84 percent, during the first five years of the GLJ Report. The majority of Penn West's proven undeveloped reserves evaluated in the GLJ Report are attributable to future oil development from CO_2 injection, infill drilling, water injection and miscible fluid injection enhanced oil recovery ("EOR") projects.

The Pembina Cardium pool is currently developed primarily on 80 acre well spacing units. Penn West believes that much of the pool could be economically developed on 40 acre spacing units or through horizontal drilling. Some of the reserves associated with these additional locations have been included in the GLJ Report as proven undeveloped reserves.

Penn West holds interests in CO_2 injection EOR properties in SE Saskatchewan and Central Alberta, a hydrocarbon injection EOR property in the Swan Hills area, operates a CO_2 injection EOR project on the Joffre Viking Tertiary Oil Unit and a hydrocarbon injection EOR project in the South Swan Hills Unit. Development of future miscible and CO_2 injection EOR reserves is scheduled over several years in order to maximize the use of existing infrastructure and available injectants.

For further information, see "Risk Factors — Resource Plays — Enhanced Oil Recovery".

Probable Reserves

GLJ has assigned 104 MMboe of Probable Reserves, of which over half (53%) are associated with major properties that are currently being produced under waterflood, miscible flood and CO_2 flood schemes. GLJ has allocated future development capital of $351 million to all Probable Reserves with $106 million scheduled for the first five years. Approximately 20 MMboe or 19% of the total Probable Reserves are associated with our working interests in three large non-operated units.

Significant Factors or Uncertainties

The development schedule of Penn West's undeveloped reserves is based on forecast and constant price assumptions for the determination of economic projects. The actual prices that occur may be significantly lower or higher resulting in some projects being delayed or accelerated, as the case may be. See "Risk Factors — Volatility of Oil and Natural Gas Prices".

Penn West does not anticipate that any significant economic factors or other significant uncertainties will affect any particular components of its reserves data. However, Penn West's reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control.

Additional Information Concerning Abandonment and Reclamation Costs

Overall costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, and facility decommissioning, remediation, and reclamation costs. These costs were estimated using Penn West's experience conducting annual abandonment and reclamation programs over the past several years.

Penn West reviews suspended or standing well bores for reactivation, recompletion or sale and conducts systematic abandonment programs for those well bores that do not meet our criteria. A portion of Penn West's liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of Penn West's liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi—location programs to reduce costs.

Penn West's total inventory is estimated at 14,578 net well bores and 1,045 facilities as of December 31, 2006. Penn West expects to incur abandonment and reclamation costs in respect to all of these wells, facilities and other properties associated with these operations.

The total amount of abandonment and reclamation costs, net of salvage values, that Penn West expects to incur, including wells that extend beyond the 50 year limit in the GLJ Report, are summarized in the following table:

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted (MM$)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% (MM$)
Total liability as at December 31, 2006	1,269	142
Anticipated to be paid in 2007	37	34
Anticipated to be paid in 2008	38	31
Anticipated to be paid in 2009	39	29

The above table includes certain abandonment and reclamation costs, net of salvage values, not included in the GLJ Report and not deducted in estimating future net revenue as disclosed earlier in this Annual Information Form. Escalated at two percent and undiscounted, the costs not deducted were $818 million and escalated at two percent and discounted at 10 percent, these costs were $91 million.

OTHER OIL AND GAS INFORMATION

Our portfolio of properties as at December 31, 2006 includes both unitized and non—unitized oil and natural gas production. In general, the properties contain long-life, low-decline rate reserves and include interests in several major oil and gas fields.

Principal Properties

The following is a description of our principal oil and natural gas properties as at December 31, 2006. Reserve amounts are stated at December 31, 2006, based on escalated cost and price assumptions as evaluated in the GLJ Report prepared by GLJ (see "Statement of Reserves Data"). Information in respect of gross and net acres and well counts is as at December 31, 2006, and information in respect of production is for the year ended December 31, 2006 except where indicated otherwise. Due to the fact that we have been active at acquiring additional interests in our principal properties, the working interest share and interest in gross and net acres and wells as at December 31, 2006 may not directly correspond to the stated production for the year, which only includes production since the date the interests were acquired by us. In particular, properties producing approximately 40,000 boe/d were acquired under the Petrofund Merger. The production from these properties was recorded effective July 1, 2006. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the application of statistical methods of aggregating individual properties.

All of the properties described below are located in the Western Canadian Sedimentary Basin and within the Canadian provinces of British Columbia, Alberta, Saskatchewan or Manitoba. The properties represent 100 percent of the total net proved plus probable reserves as assigned by GLJ in the GLJ Report. There are no material properties to which reserves have been attributed which are capable of producing but which are not producing.

Major Operating Regions

The following table shows Penn West's reported average daily production and Proved plus Probable Reserves, as at December 31, 2006, by major core region:

	Average Daily Production			Proved Plus Probable Gross Reserves			
	Crude Oil and NGLs (bbl/d)	Natural Gas (MMcf/d)	Total (boe/d)	Crude Oil and NGLs (MMbbl)	Natural Gas (Bcf)	Total (MMboe)	Undeveloped Land (000 net acres)
Central	36,916	133	59,142	190.9	450.2	267.1	1,305
Plains	33,640	95	49,412	124.6	221.5	162.8	1,365
Northern	1,934	117	21,456	7.1	289.2	56.0	1,045
Total	72,490	345	130,010	322.6	960.9	485.9	3,715
	56% of daily production	44% of daily production		67% of total reserves	33% of total reserves		

Oil and Natural Gas Properties

Penn West's production and reserves are attributed to more than 400 producing properties. No single property accounts for more than 10 percent of Penn West's reserves. A general discussion of our operations and activities in each of our core areas follows.

Northern Area

The Northern Area currently provides approximately 34 percent of Penn West's natural gas production and three percent of its liquids production, based on 2006 exit rate production. Geographically, the area encompasses the land base north of Township 90 in Alberta and extends into the Peace River Arch and Northeastern regions of British Columbia. Approximately 43 percent of the Northern Area's gas is produced from the Wildboy field in Northeast British Columbia. Gas is produced from two primary zones in Wildboy; the Mississippian at a depth of approximately 600 metres, and the Jean Marie at approximately 1,300 metres. Penn West has net undeveloped land holdings of approximately 1,045,000 acres in the Northern Area.

The exploration and development of the 100 percent owned Wildboy field followed a Penn West discovery in 1995. Since then, development of the field has continued through the drilling of horizontal and vertical wells, the addition of field booster compression and the subsequent expansion of the plant process and sales line to Alberta to accommodate the increased volumes. Raw throughput of the facility averaged 69 MMcf/d for 2006.

Penn West drilled 33 wells in the Northern Area in 2006, with 2007 plans focusing on additional field compression and wellbore optimization in Wildboy, as well as an extensive 2D and 3D Mississippian seismic program in Wildboy, in preparation for possible drilling in the 2008 season. The Peace River Arch area currently provides approximately four percent of Penn West's total production. In 2006, Penn West drilled 15 wells in the Firebird area and two at Buick Creek. Plans for 2007 are focused on wellbore optimization at Firebird, Spirit River and Cecil Lake, with current plans for 2008 to drill 18 locations in Firebird. Penn West currently holds approximately 74,000 net acres of undeveloped land in the Peace River Arch area.

Central Area

The Central Area currently provides approximately 39 percent of Penn West's natural gas production and 51 percent of its liquids production based on 2006 exit rate production. The region contains large, long-life pools of Cardium light oil, oil sands deposits in the Peace River Oil Sands area and shallow to medium-depth, multi-zone natural gas pools. This region is both an established producing area and an area of significant potential reserves and production growth. Penn West's long-life, low decline rate Cardium oil reserves in the Central Area provide a stable source of premium quality light oil. Cardium oil receives a price very close to the Edmonton par price. Penn West holds approximately 1,305,000 net acres of undeveloped land in the Central Area.

The Central Area is also a significant natural gas producing area, with production of 133 MMcf/d at year-end 2006. The natural gas prospects in the area tend to be multi-zone and relatively liquids rich. Penn West's control of several natural gas processing facilities throughout the area allows Penn West to gain economies of scale in the surrounding natural gas operations. One of our principal facilities in the Central Area is the Minnehik-Buck Lake natural gas processing facility in which Penn West controls a majority interest. The facility has the capacity to process over 120 MMcf/d of natural gas including the capability to process sour natural gas.

Central — Peace River Oil Sands

Since 2002, Penn West has grown its land base to approximately 300,000 net acres of 100 percent owned oil sands leases in the Peace River oil sands area. As of the end of 2006, we have drilled 54 horizontal wells and seven stratigraphic wells in the focus areas of Seal Main, Seal North and Cadotte. In 2006, Penn West acquired a 35 percent working interest in a 13,500 bbl/d facility and a 15 percent working interest in a 55,000 bbl/d pipeline. In 2007, 30 stratigraphic wells and 80 to 90 net horizontal wells are planned, with capital programs of approximately $175 million, excluding acquisitions. Penn West currently estimates the project area contains 6.8 billion barrels of heavy oil resources in place. This estimate represents the mid case. Using the definitions set out in the COGE Handbook, these resources are considered "Discovered Resources". As Penn West is in the early stages of the project, these resources have not been classified into more specific categories. There is no certainty that a significant portion of these resources will be recovered or that a significant portion of the resources will be economically or technically feasible to produce in the future. Discovered resources are those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered

resources consist of economic and uneconomic resources with the estimated future recoverable portion classified as reserves or contingent resources.

Central-Pembina

Pembina produces high-netback, long-life, low-decline light oil and liquids-rich natural gas. Approximately 1,150 operated producing wellbores account for 14,400 bbl/d or 11 percent of our 2006 production. The Petrofund Merger further consolidated Penn West's land position in the area, lifting our average working interest to approximately 87 percent and increasing overall operated volumes by about 20 percent or approximately 2,900 boe/d. Our share of current Pembina area production is approximately 18,900 boe/d including operated and non-operated volumes.

The group of properties is centred on the extensive, long-life Cardium oil pool. The pool's secondary recovery (water flood) phase is currently

being optimized while our EOR team prepares the plans to expand the CO_2 flood to other areas.

The Pembina field team's overall focus is on low-risk drilling and low-cost optimization opportunities that are aimed at maximizing distributions to the Trust's Unitholders and reinvestment capital for Penn West's long-term resource plays. Costs are kept down to increase netbacks by exploiting Penn West's large network of operated infrastructure, which includes seven gas plants, numerous oil batteries and over 3,000 kilometres of oil and gas gathering lines.

The Pembina Cardium pool is relatively lightly-drilled with many opportunities for conventional exploration and development of shallow through deep targets. Pembina has an array of multizone potential throughout the area, including the Edmonton Sands, Belly River, Cardium, Glauconite, Ellerslie, Rock Creek, Pekisko, Banff and some deep Swan Hills.

Penn West drilled 18 gross wells in 2006, with plans for a 2007 drilling program of 17 wells. This drilling program is a mix of low-risk cardium infill wells, development wells and a deep gas well. As in 2006, Penn West continues to strive to improve efficiency of operations to maximize oil and gas recovery through the use of geological and reservoir studies and enhanced recovery methods.

Central - - Willesden Green

Located south of Pembina, Willesden Green is an area of long-life and low-decline light oil and liquids-rich natural gas from multiple zones. Control of key infrastructure improves our returns by providing us with operational control.

Willesden Green is an active development area. The 17 development and exploitation wells planned in 2007 (up from 10 wells in 2006) are intended to fully offset natural production declines. We retain deep mineral rights throughout the area, enhancing longer-term exploration potential for Penn West or drilling partners.

Over the past two years, the production from the Willesden Green area has remained relatively constant through oil and gas well drilling and optimization of the area's wells and infrastructure. In addition, the area has one of our highest netbacks due to its mix of light oil, liquids rich natural gas, low royalty rates and relatively low net operating costs. Penn West controls the area's oil and natural gas gathering infrastructure that is centred on our 100 percent-owned Willesden Green gas plant. In 2006, Penn West de-bottlenecked its gas gathering and gas processing infrastructure, increasing the plant's capacity to process additional Penn West and third-party volumes.

In 2006, seven infill wells were drilled focusing on the 100 percent working interest Cardium oil and Belly River natural gas pools. For 2007, we will drill eight wells, and will pursue a multi-year program to downspace the Cardium from one well per 80-160 acres to one per 40 acres.

Central — Swan Hills

Penn West holds a majority interest in the South Swan Hills Unit, as well as other interests in the area. South Swan Hills is a light oil pool where a combination of water and miscible hydrocarbon injection is used to increase recovery factors.

The South Swan Hills Unit is also the site of two new pilot projects: The Mannville horizontal coal bed methane ("CBM") project, which is currently beginning production operations and the Swan Hills CO_2 pilot, which is scheduled to begin construction later in 2007.

The CBM pilot was drilled in late 2006 and has been on production since early 2007. The pilot wells are currently in the process of dewatering the wells before gas production can occur. Based on production experience at the offsetting successful

Trident/Nexen's Corbett Creek CBM property, the dewatering process could take between six and 12 months for the initial pilot wells, shortening as development takes place and the coals are de-pressured. Pending the success of the pilot project, full-scale CBM development could take place over the next four years.

The planned CO_2 pilot in South Swan Hills will target portions of the Swan Hills reef complex that have not been efficiently miscible flooded in the past. This pilot will also help in the evaluation of the potential of using CO_2 flooding in the East Swan Hills Unit, which has not undergone any miscible flooding to date, but is geologically similar to the CO_2 pilot area.

The Petrofund Merger in 2006 also resulted in new or increased working interests in the Swan Hills Unit #1, House Mountain Unit, Mitsue Unit, and the Kaybob Unit. Additional working interests were acquired in the Otter and Red Earth areas with new production in the Loon and Ogston areas also acquired.

Plains Area

The Plains Area is a shallow depth region with multi-zone potential that supplies 28 percent of Penn West's natural gas production and 46 percent of the liquids based on 2006 exit rate production. In 2006, Penn West drilled 148 net wells in this area. Target zones include the Bakken, Mannville and Viking. Extensive 2D and 3D seismic is used to select drilling locations. Penn West owns and operates an extensive infrastructure of gas plants, batteries and pipelines in the Plains Area. In 2007, Penn West plans to drill 95 net wells and holds approximately 1,365,000 net acres of undeveloped land in the area.

Plains — Wainright

Key characteristics of the Wainright property group include: extensive developed and undeveloped lands, high working interests, low-decline heavy oil and Viking natural gas production, and widespread infrastructure. These advantages allow Penn West to continually optimize operations while adding new production at low risk and cost throughout the area.

In 2006, investment of $17 million funded 200 separate optimization projects. Development drilling added 640 bbl/d in new volumes. Complemented by properties at Sugden, Consort, and Ribstone acquired with the Petrofund Merger, the Wainwright group of properties generated overall volumes of 9,300 bbl/d or approximately seven percent of the Trust's 2006 exit production.

Plains — Hoosier — Coleville

Hoosier and Coleville consist of more than 20 producing properties around Hoosier and form one of Penn West's most active development areas. These mostly Penn West operated assets include approximately 4,210 producing wellbores, a high average working interest of over 95 percent, extensive Penn West infrastructure and a combined 918,000 acres of lands, of which 396,000 net acres are undeveloped. The Petrofund Merger added geographically and technically complementary properties to the Hoosier group, increasing the area's production by 10 percent.

Hoosier's primary commodity is cold-pumped conventional heavy oil. The main geological targets are the seismically defined Mannville Group, Bakken and geographically vast Viking horizons, all at depths shallower than 850 metres. Penn West drilled 97 wells throughout Hoosier in 2006, including 34 vertical wells, 16 horizontal wells and 47 natural gas wells. The program added 1,550 bbl/d of crude oil and four MMcf/d of natural gas with additional new capacity "behind pipe" to be tied in during 2007.

In 2007, Penn West has budgeted $47 million to drill 51 vertical wells and eight horizontal wells in Hoosier. The main focus will be oil development driven by the scope of medium-term opportunities rather than short-term price volatility.

Plains — South and Other Area

The Plains South Area is a proven producing region with long-life light oil reserves from a variety of stratigraphic zones producing a total of approximately 17,200 bbl/d. These properties stretch from the Rocky Mountains to western Manitoba and 200 kilometres north from the U.S. border. This large geographic region includes many opportunities for development and optimization.

We acquired a 21.1 percent interest in the Weyburn Unit located in Southeast Saskatchewan in the Petrofund Merger. Weyburn is Canada's largest commercial CO_2 enhanced oil recovery project, producing approximately 30,000 bbl/d (approximately 6,300 bbl/d net to us) at December 31, 2006, sourcing CO_2 for injection from a coal gasification plant in North Dakota. Our share of capital costs was $43.2 million in 2006 increasing to approximately $44.8 million in 2007 due to

increases to the rate of CO_2 injection and the drilling of additional wells. The application of CO_2 miscible flooding increased the estimated 30 percent oil recovery rate under water flooding to an estimated 46 percent under CO_2 enhanced recovery. With the Petrofund Merger, we also increased our working interest in the Midale Unit to approximately 8.7 percent where CO_2 flooding will occur using the same CO_2 source as Weyburn.

Additional Information

None of Penn West's important properties, plants, facilities or installations are subject to any material statutory or other mandatory relinquishments, surrenders, back-ins or changes in ownership.

For a discussion of properties to which reserves have been attributed and which are capable of producing but which are not producing, see "Statement of Reserves Data - Additional Information Relating to Reserves Data — Undeveloped Reserves".

Oil And Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2006.

	Producing				Non-Producing		Total	
	Oil		Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	6,122	4,065	3,280	2,117	4,135	2,837	13,537	9,019
British Columbia	48	20	468	304	200	136	716	460
Saskatchewan	3,640	3,019	661	536	1,713	1,344	6,014	4,899
Manitoba	137	129	—	—	76	71	213	200
Total	9,947	7,233	4,409	2,957	6,124	4,388	20,480	14,578

Undeveloped Land Holdings

The following table sets out our undeveloped land holdings as at December 31, 2006.

	Undeveloped Acres (000s)	
	Gross	Net
Alberta	2,715	2,422
British Columbia	625	497

Saskatchewan	693	654
Manitoba	143	142
Total	4,176	3,715

We currently have no material work commitments on these lands. The primary lease or extension term on 1,030,000 net acres will expire by December 31, 2007. The right to explore, develop and exploit these leases will be surrendered unless we qualify them for continuation based on existing production, drilling or technical mapping.

Tax Horizon

Under currently enacted legislation, as a result of our tax structure, taxable income is transferred from our operating entities to the Trust and from the Trust to Unitholders. This is primarily accomplished through the deduction by our operating entities of the royalties on underlying oil and gas properties and the deduction of interest on the Notes. The terms of the Trust Indenture require the Trust to distribute all of its taxable income, therefore, it is currently expected that no income tax liability will be incurred provided we maintain this organizational structure. To the extent that taxable income is retained in our operating entities to fund capital expenditures or repay bank debt, it is possible that income taxes could be payable at some time in the future. If the proposed changes to the taxation of income trusts are enacted, taxes could be exigible in the Trust as certain distributions would no longer be a deduction in the calculation of its taxable income. For more information on these proposals, see "Description of Our Business — Proposed Federal Tax Changes" and "Risk Factors — Proposed Federal Tax Changes".

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds) related to our activities for the year ended December 31, 2006:

	2006 MM$	2005 MM$
Property Acquisitions		
Proved Properties	$ 5.6	$ (5.8)
Undeveloped Properties	19.8	13.5
Exploration Costs(1)	82.9	140.4
Development Costs(2)	462.7	299.3
Corporate Costs	6.9	9.3
Capital Expenditures	577.9	456.7
Petrofund Merger	3,323.3	—
Total Expenditures	$3,901.2	$ 456.7

Notes:
(1) Costs of land acquired, geological and geophysical capital expenditures and drilling costs for 2006 exploration wells drilled.
(2) Includes equipping and facilities capital expenditures.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells that we participated in during the year ended December 31, 2006:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	27	26	166	123
Natural Gas	46	40	135	65
Dry	2	2	15	14
Total	75	68	316	202

We initially estimated capital expenditures of $550 million to $650 million in 2007 to execute our capital programs. The primary components of our program are described under the heading "Other Oil and Gas information — Oil and Natural Gas Properties". 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.

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2007 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Statement of Reserves Data - Disclosure of Reserves Data".

	Light and Medium Oil (bbl/d)		Heavy Oil (bbl/d)		Natural Gas (Mcf/d)		Natural Gas Liquids (bbl/d)		Total (Boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Producing	39,000	34,168	19,749	17,544	295,371	233,485	5,962	4,164	113,939	94,789

Proved Developed Non-Producing	616	500	407	340	13,888	10,546	213	148	3,551	2,746
Proved Undeveloped	1,323	1,042	382	293	1,672	1,305	72	52	2,056	1,604
Total Proved	40,939	35,710	20,538	18,177	310,931	245,336	6,247	4,364	119,546	99,139
Total Probable	807	563	893	171	16,561	12,401	197	140	4,656	3,487
Total Proved PlusProbable	41,746	36,273	21,431	18,894	327,492	257,737	6,444	4,504	124,202	102,626

Production History

The following tables summarize certain information in respect of our production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended 2006				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2006
Average Daily Production(1)					
Light and Medium Crude Oil (bbl/d)	27,441	26,646	42,150	42,898	34,847
Heavy Oil (bbl/d)	20,685	18,625	21,186	22,586	20,776
Gas (MMcf/d)	266.9	267.9	359.1	354.6	312.5
NGLs (bbl/d)	4,100	3,331	5,879	5,335	4,668
Combined (boe/d)	96,713	93,242	129,059	129,915	112,369
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	63.42	73.20	72.27	58.51	66.46
Heavy Oil ($/bbl)	30.76	52.85	52.20	37.57	43.07
Gas ($/Mcf)	8.12	6.14	5.97	6.97	6.75
NGLs ($/bbl)	53.19	62.08	55.75	48.76	54.31
Combined ($/boe)	49.23	51.33	51.33	46.88	49.58
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	9.36	8.83	10.40	9.38	9.58
Heavy Oil ($/bbl)	4.85	8.50	7.50	5.44	6.51
Gas ($/Mcf)	1.78	1.43	1.28	1.61	1.51
NGLs ($/bbl)	17.58	21.05	15.87	16.91	17.46
Combined ($/boe)	9.36	9.09	8.90	9.12	9.10
Operating Expenses (2)(3)					
Light and Medium Crude Oil ($/bbl)	15.64	16.38	16.57	15.53	16.03
Heavy Oil ($/bbl)	10.55	11.49	10.93	11.88	11.22
Gas ($/Mcf)	0.94	0.97	1.00	1.04	0.99
NGLs ($/bbl)	13.87	13.85	14.43	13.98	14.09
Combined ($/boe)	9.88	10.26	10.64	10.61	10.39
Transportation					
Light and Medium Crude Oil ($/bbl)	—	—	—	—	—
Heavy Oil ($/bbl)	0.15	—	0.07	0.07	0.07
Gas ($/Mcf)	0.23	0.21	0.23	0.18	0.21
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	0.66	0.60	0.64	0.51	0.60
(Gain)/Loss on Risk Management Contracts					
Light and Medium Crude Oil ($/bbl)	—	2.37	2.24	0.01	1.14
Heavy Oil ($/bbl)	—	—	—	—	—
Gas ($/Mcf)	(0.22)	(0.93)	(1.07)	(0.56)	(0.72)
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	(0.62)	(2.00)	(2.23)	(1.53)	(1.64)
Netback Received(4)					
Light and Medium Crude Oil ($/bbl)	38.41	45.60	43.05	33.58	39.70
Heavy Oil ($/bbl)	15.21	32.86	33.70	20.18	25.27
Gas ($/Mcf)	5.39	4.46	4.53	4.70	4.76
NGLs ($/bbl)	21.74	27.18	25.40	17.87	22.75
Combined ($/boe)	29.95	33.38	33.38	28.17	31.13

Notes:

(1) Before deduction of royalties.

(2) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.

(3) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalties, operating costs, transportation and losses/gains on commodity and foreign exchange contracts from revenues.

No property accounts for more than nine percent of the production disclosed above. For more information, see "Other Oil and Gas Information — Principal Properties".

Marketing and Future Commitments

Our marketing approach continues to reflect the following principles:

- Maximize production from existing assets and avoid any shut-in production due to marketing constraints.
- Diversify natural gas pricing on a geographic basis in order to maintain competitive prices.
- Optimize netbacks on crude oil production through blending, trucking and proprietary handling of emulsion.

Natural Gas Marketing

In 2006, Penn West received an average price from the sale of natural gas, including hedging gains, of $7.47/Mcf compared to $8.74/Mcf realized in 2005. Approximately 85 percent of our natural gas sales are marketed directly with the balance of natural gas sales marketed in aggregator pools. We continue to maintain a significant weighting to the Alberta market as this market offers a premium netback relative to most other indices. In addition to maximizing netbacks, the current portfolio approach also enhances our operational flexibility to pursue higher netback opportunities as they become available.

We continue to conservatively manage our transportation costs. Transportation on all pipelines is closely balanced to supply, and market commitments related to export transportation represented less than five percent of sales.

Oil and Liquids Marketing

The average quality of our crude oil production is 28 º API. Approximately 61 percent of our liquids production can be attributed to light and medium oil, with an average API of 36º. Conventional heavy oil, at 15 º average API, comprises approximately 33 percent of total liquids production. Production of NGLs account for approximately six percent of total liquids production.

We market our production at the lease level on varying term contracts that capture premiums on postings for the majority of corporate sales and actively manage our heavy oil supply by finding opportunities to optimize netbacks through blending, trucking and proprietary handling of emulsion. Blending costs are also controlled through the use of proprietary condensate supply.

The following table summarizes the net product price received for our production of conventional light and medium oil and conventional heavy oil for the periods indicated:

	2006		2005	
Quarter ended	Light and Medium Oil ($/bbl)	Heavy Oil ($/bbl)	Light and Medium Oil ($/bbl)	Heavy Oil ($/bbl)
March 31	63.42	30.76	57.62	28.06
June 30	73.20	52.85	61.01	31.22
September 30	72.27	52.20	73.76	48.60
December 31	58.51	37.57	64.56	34.95

Forward Contracts

Our Board of Directors approved a policy that enables us to hedge up to 50 percent of our liquids and natural gas price exposure (net of royalties) for a maximum of two years and up to 75 percent for a maximum of one year. As at December 31, 2006 Penn West was not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or from being protected from the full effect of, future market prices for oil or natural gas except for the following financial hedging positions that were outstanding as at December 31, 2006:

	Notional Volume	Remaining Term	Pricing	Market Value(1) (MM$)
Crude Oil				
WTI Costless Collars	3,000 bbl/d	Jan/-Mar/07	US$56.67-$84.28 bbl	0.2
WTI Costless Collars	1,000 bbl/d	Jan/-Jun/07	US$60.00-$73.10 bbl	0.2
WTI Costless Collars	1,000 bbl/d	Apr/-Jun/07	US$60.00-$80.00 bbl	0.2
WTI Costless Collars	25,000 bbl/d	Jan/-Dec/07	US$56.00-$83.80 bbl	7.9
WTI Costless Collars	10,000 bbl/d	Jan/-Jun/08	US$60.00-$94.55 bbl	6.2
Natural Gas				
AECO Costless Collars	9,200 Mcf/d	Jan/-Mar/07	$ 9.18-$12.97/Mcf	1.0
AECO Costless Collars	73,400 Mcf/d	Jan/-Oct/07	$ 7.63-$9.68/Mcf	20.8

Electricity					
Alberta Power Pool Swaps	67 MW	2007	$	49.50 MWH	17.3
Alberta Power Pool Swaps	2 MW	2008	$	57.00 MWH	0.4
Interest Rate Swaps	$ 100.0 million	Jan/07-Mar/08		4.356%	(0.2)
					54.0

Note:
(1) Unrealized gain (loss) based on calculations using posted rates for similar contracts on December 31, 2006.

Our transportation obligations and commitments for future physical deliveries of crude oil and natural gas do not exceed our expected related future production from our proved reserves, estimated using forecast prices and costs.

Future Commitments

We have committed to certain payments over the next five years, in addition to regular payments under our credit facilities, 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

Note:
(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.

Environmental Matters

The oil and natural gas industry is subject to environmental regulations under provincial and federal legislation. Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with this legislation can require significant expenditures; a breach of such requirements could result in the imposition of material fines and facility closures. Penn West's environmental programs are monitored to ensure that they comply with all government environmental regulations and with Penn West's own environmental policies. The results of these programs are reviewed with Penn West's management and operations personnel.

In December 2002, the Government of Canada ratified the Kyoto Protocol that became legally binding on February 16, 2005. This protocol calls for Canada to reduce its greenhouse gas emissions to six percent below 1990 levels during the period between 2008 and 2012. Details of specific requirements relating to the oil and gas industry have not been enacted and accordingly the impact of the Kyoto Protocol is unknown.

The Government of Canada has announced its intention to regulate greenhouse gases (GHG) and other air pollutants. The Government is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce GHG emissions by 45 percent to 65 percent by 2050 and a commitment to regulate industry on an emissions intensity basis in the short-term. Currently there are few technical details regarding the implementation of the Government's plan to regulate industrial GHG emissions, but the Government has made a commitment to work with industry to develop the specifics.

The Alberta Government has also released draft regulations that will require facilities that emit over 100,000 tonnes of CO_2E/yr (total Greenhouse Gases in terms of CO_2 equivalent) to reduce their emissions intensity (quantity of gases releases per unit of production) by 12 percent starting July 1, 2007. Facilities that do not reduce their emissions intensity by this amount will either be charged $15/tonne for every tonne they emit in excess of the 12 percent target or they will have to invest in projects outside of their facility, but still in Alberta, that reduce or offset emissions on their behalf. Penn West currently does not operate any facilities that fall under the current regulations but it does have a working interest in some facilities that do. The full impact of this regulation is currently unknown but it is very likely that these targets will result in increased operating costs for facilities that are under these regulations. However, Penn West believes that this new regulation will be of overall benefit to the Trust as it will most likely result in increased interest in CO_2 capture and storage technologies and infrastructure that will increase the speed of development of its CO_2 injection plans in Pembina.

As the federal and provincial programs are under development, Penn West is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that we could face increases in operating costs in order to comply with GHG emissions legislation. However, Penn West in cooperation with the Canadian Association of Petroleum Producers will continue to work with the Government to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector. In the meantime, we will continue our current activities to reduce emissions intensity, improve energy efficiency and develop CO_2 injection and sequestration infrastructure. See "Risk Factors — Environmental" and "Risk Factors — Kyoto Protocol".

We fully understand our responsibilities of reducing the environmental impacts from our oil and recognize the interests of other land users in

resource development areas, and conduct our operations accordingly. We are committed to reducing the environmental impact from oil and natural gas operations, and to involving stakeholders throughout the exploration, development, production and abandonment process. Our environmental programs encompass resource conservation, stakeholder communication, carbon dioxide sequestration and site abandonment/reclamation.

Our Environmental Policy and Environmental Management Plan ("EMP") encompass the full range of air, water, soil and waste issues associated with exploration, development and production. The EMP includes guidelines to 11 key areas that are considered in conjunction with oil and natural gas development plans. These guidelines help ensure safe and environmentally sound field operations. The Environmental Operating Guidelines are used to train our employees in the practical and economical implementation of the EMP.

We maintain a program of detailed inspections, audits and field assessments to determine and quantify the environmental liabilities that will be incurred during the eventual decommissioning and reclamation of our field facilities. Penn West pursues a program of environmental impact reduction aimed at minimizing these future corporate liabilities without hampering field productivity. This program, launched in 1994 and ongoing into 2007, includes measures to remediate potential contaminant sources, reclaim spill sites and abandon unproductive wells and shut-in facilities. We have implemented strategies to reduce greenhouse gas emissions and flaring and continued the program to plan and test the infrastructure required to inject and permanently "sequester" carbon dioxide in hydrocarbon reservoirs.

During 2006, we continued our pilot-scale carbon dioxide injection program at Pembina, with injection of carbon dioxide commencing in February 2005. To date, in excess of one billion cubic feet of carbon dioxide has been injected. If successful, the pilot could lead to a much larger enhanced oil recovery program with potential to sequester very significant volumes of carbon dioxide. Also in 2006, we continued to participate in studies to develop a cost effective system to source large volumes of carbon dioxide currently emitted within Alberta, and to transport it by pipeline for injection into producing oil fields in central Alberta. See "Risk Factors — Resources Plays — Enhanced Oil Recovery".

CAPITALIZATION OF PENN WEST PETROLEUM LTD.

Common Shares

Penn West Petroleum Ltd. has authorized for issuance an unlimited number of common shares. We own all of the issued common shares. The voting of such shares is delegated to the Board of Directors under the Trust Indenture other than: (i) any sale, lease or other disposition of, or any interest in, all or substantially all of our assets, except in conjunction with an internal reorganization of our direct or indirect assets as a result of which we have the same, or substantially similar, interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization; (ii) any statutory amalgamation of Penn West Petroleum Ltd. with any other entity, except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iii) any statutory arrangement involving Penn West Petroleum Ltd., except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iv) any amendment to the articles of Penn West Petroleum Ltd. to increase or decrease the minimum or maximum number of directors; or (v) any material amendment to the articles of Penn West Petroleum Ltd. to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of Penn West Petroleum Ltd.'s shares in a manner which may be prejudicial to us, without the approval of the Unitholders by special resolution at a meeting of Unitholders called for that purpose.

The holders of common shares are entitled to receive notice of and to attend all meetings of the shareholders of Penn West Petroleum Ltd. and to one vote at such meetings. The holders of common shares will be, at the discretion of the Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board of Directors on the common shares. The holders of common shares will be entitled to share equally in any distribution of the assets of Penn West Petroleum Ltd. upon the liquidation, dissolution, bankruptcy or winding-up of Penn West Petroleum Ltd. or other distribution of its assets among its shareholders for the purpose of winding-up its affairs subject to the rights, privileges, restrictions and conditions attaching to any other shares having priority over the common shares.

Preferred Shares

Penn West Petroleum Ltd. is authorized to issue an unlimited number of Preferred Shares in series. Before any shares of a particular series are issued, the Board of Directors shall, by resolution, fix the number of shares that will form such series and shall, subject to the limitations set out herein, by resolution fix the designation, rights, privileges, restrictions and conditions to be attached to the Preferred Shares of such series. The Preferred Shares of each series shall rank on a parity with the Preferred Shares of every other series with respect to accumulated dividends and return of capital. The Preferred Shares are entitled to a preference over the Common Shares and over any other shares of Penn West ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of Penn West, whether voluntary or involuntary, or any other distribution of the assets of Penn West among its shareholders for the purpose of winding-up its affairs. As at the date hereof, no Preferred Shares are issued and outstanding.

Borrowing

We borrow funds from time to time to finance the purchase of properties, for capital expenditures or for other financial obligations or expenditures in respect of properties held by us or for working capital purposes.

Certain debt service charges on borrowed funds attributable to our properties will be deducted in computing income under the NPIs. Capital expenditures and any debt repayment will be scheduled to minimize any income tax payable by Penn West Petroleum Ltd.

The credit facilities contain provisions which restrict the ability of Penn West Petroleum Ltd. to pay the Trust under the NPIs and interest under the Notes and thereby may restrict distributions to Unitholders in the event of the occurrence of certain events of default. For more information, reference is made to note 6 of our consolidated financial statements for the year ended December 31, 2006, which are incorporated by reference in this Annual Information Form and which are filed on SEDAR at www.sedar.com. For more information, see "Risk Factors — Debt Service".

INFORMATION RELATING TO THE TRUST

Trust Units

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units share equally in all distributions made by us and all Trust Units carry equal voting rights at meetings of Unitholders. No Unitholder will be liable to pay any further calls or assessments in respect of the Trust Units. No conversion, retraction or pre-emptive rights attach to the Trust Units.

Special Voting Units

The Trust Indenture also provides for the issuance of special voting units and which are entitled to such number of votes at meetings of Unitholders and any other rights or limitations prescribed by the Board of Directors when the Board of Directors authorizes issuing such special voting units. The Trust Units and the special voting units vote together as a single class on all matters. In the event of our liquidation, dissolution or winding-up, the holders of special voting units will not be entitled to receive any of our assets available for distribution to our Unitholders. The holders of special voting units will not be entitled to receive dividends or other distributions from us.

Trust Indenture

The Trust Indenture, among other things, provides for the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the Trustee and the form of Trust Unit certificates. The Trust Indenture may be amended from time to time. Substantive amendments to the Trust Indenture, including early termination of the Trust and the sale or transfer of our property as an entirety or substantially as an entirety requires approval by special resolution of the Unitholders. See “Information Relating to the Trust — Meetings and Voting” below.

The following is a summary of certain provisions of the Trust Indenture. For a complete description of such indenture, reference should be made to the Trust Indenture, a copy of which has been filed on SEDAR at www.sedar.com.

Trustee

CIBC Mellon Trust Company was appointed our trustee on May 27, 2005, and also acts as the transfer agent for the Trust Units. The Trustee is responsible for, among other things, accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto and maintaining our books and records and providing timely reports to holders of Trust Units. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in our best interests and in the best interest of the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The initial term of the Trustee’s appointment is until the third annual meeting of Unitholders. The Unitholders shall, at the third annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the Unitholders are required to re-appoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the re-appointment or appointment of the successor to the Trustee. The Trustee may also be removed by special resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Penn West Petroleum Ltd. presently administers us on behalf of the Trustee. Penn West Petroleum Ltd., on behalf of the Trustee, keeps such books and records as are necessary for the proper recording of our business transactions.

The Trust Indenture provides that the Trustee shall be under no liability for any action or failure to act unless such liabilities arise out of the Trustee’s negligence, wilful default or fraud. The Trustee is indemnified out of our assets for any liabilities relating to any taxes or other government charges imposed upon the Trustee or in consequence of its performance of its duties unless such liabilities arise principally and directly out of gross negligence, wilful default or fraud of the Trustee, but has no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

The Trust Indenture also provides that the Trustee may without Unitholder approval amend the articles of Penn West Petroleum Ltd. to issue shares of Penn West Petroleum Ltd. which are exchangeable for Trust Units. There are no exchangeable shares issued or outstanding.

Future Offerings

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee, upon the recommendation of the Board of Directors may determine. The Trust Indenture also provides that Penn West Petroleum Ltd. may authorize the creation and issuance of debentures, notes and other evidences of indebtedness by us which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as the Board of Directors may determine.

Meetings and Voting

Meetings of the Unitholders will be held annually. Special meetings of Unitholders may be called at any time by the Trustee and shall be called by the Trustee upon the written request of Unitholders holding in aggregate not less than 20 percent of the Trust Units. Notice of all meetings of Unitholders shall be given to Unitholders at least 21 days prior to the meeting.

Unitholders will be entitled at each annual meeting to appoint our auditors and to elect all the members of the Board of Directors.

Our Management

The Board of Directors has generally been delegated all of our significant management decisions pursuant to the Trust Indenture and the Administration Agreement. For more information, see "Corporate Governance".

Penn West Petroleum Ltd. has accepted all such delegation and has agreed that, in respect of such matters, it shall carry out its functions honestly, in good faith and in our best interests and the best interests of the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonable person would exercise in comparable circumstances.

Limitation on Non-Resident Ownership

In order that we maintain our status as a "mutual fund trust" under the *Income Tax Act* (Canada), certain provisions of the *Income Tax Act* (Canada) require that we not be established nor maintained primarily for the benefit of non-residents of Canada ("non-residents"). The Trust Indenture provides that the Trust will use its best commercial efforts to maintain its status as a mutual fund trust under the *Income Tax Act* (Canada). See "Risk Factors — Non-Resident Ownership of Trust Units".

Right of Redemption

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the least of: (i) 95 percent of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; (ii) 95 percent of the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption, and (iii) 95 percent of the closing market price of the Trust Units on the date of redemption.

For the purposes of this calculation, "market price" will be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The closing market price shall be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the

highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The Market Redemption Price payable by the Trust in respect of any Trust Units tendered for redemption during any calendar month shall be satisfied by way of cheque payable on the last day of the calendar month following the month in which the Trust Units were tendered for redemption. The entitlement of Unitholders to receive a cheque upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month shall not exceed $250,000 provided that, Penn West may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the calendar month following such month by the Trust distributing redemption notes of Penn West Petroleum Ltd. to the Unitholders who exercised the right of redemption.

The redemption notes will be due on the third anniversary of the date of issuance and will bear interest at a rate per annum to be set by the directors of Penn West Petroleum Ltd. in the context of the prevailing interest rates for debt instruments having equivalent terms and conditions. The redemption notes will be issued under a trust indenture and will provide for their issuance to the Trust in consideration of cash or as a reduction in the principal amount of the Notes.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Redemption notes which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such redemption notes. Redemption notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Termination of the Trust

The Unitholders may vote to terminate the Trust at any meeting of the Unitholders, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20 percent of the Trust Units; (b) a quorum of 50 percent of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by special resolution of the Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will liquidate all our assets, pay, retire, discharge or make provision for some or all of our obligations and then distribute the remaining proceeds of sale to Unitholders.

Reporting to Unitholders

Our financial statements will be audited annually by an independent recognized firm of chartered accountants. Our audited financial statements, together with the report of such chartered accountants, will be mailed by the Trustee to Unitholders if previously requested and, if previously requested, the unaudited interim financial statements will be mailed to Unitholders within the periods prescribed by securities legislation. Our year end is December 31. We are also subject to the continuous disclosure obligations under all applicable securities legislation.

Unitholders are entitled to inspect, during normal business hours, at the offices of the Trustee, and, upon payment of reasonable reproduction costs, to receive photocopies of the Trust Indenture and a listing of the registered holders of Trust Units.

CORPORATE GOVERNANCE

General

In general, Penn West Petroleum Ltd. has been delegated responsibility for substantially all of the management decisions of the Trust. The Unitholders are entitled to elect all of the Board of Directors pursuant to the terms of the Trust Indenture.

Trust Indenture

Pursuant to the Trust Indenture, Unitholders are entitled to direct the manner in which we will vote our common shares in Penn West Petroleum Ltd. at all meetings in respect of matters relating to the election of the directors of Penn West Petroleum Ltd., approving its financial statements and appointing auditors of Penn West

Petroleum Ltd. who shall be the same as our auditors. Prior to us voting our common shares in Penn West Petroleum Ltd., in respect of such matters, each Unitholder is entitled to vote in respect of the matter on the basis of one vote per Trust Unit held, and we are required to vote our common shares in Penn West Petroleum Ltd. in accordance with the result of the vote of Unitholders.

Decision Making

The Board of Directors has a mandate to supervise the management of our business and affairs, Penn West Petroleum Ltd. and our other direct or indirect subsidiaries and partnerships and to act with a view to our best interest. The Board of Directors' mandate includes: (i) any offering of securities; (ii) ensuring compliance with all applicable laws, including in relation to an offering of securities; (iii) all matters relating to the content of any documents relating to an offering of securities, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of, material contracts; (v) all matters concerning any subscription agreement or underwriting or agency agreement providing for the sale or issue of Trust Units or securities convertible for or exchangeable into Trust Units or rights to acquire Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments; (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture (ix) the adoption of a Unitholder rights plan and other miscellaneous matters relating to the maximization of Unitholder value; and (x) all matters relating to amending Penn West Petroleum Ltd.'s articles to create exchangeable shares. The Board of Directors holds regularly scheduled meetings at least quarterly to review the business and affairs of our subsidiaries, partnerships and trusts and make any necessary decisions relating thereto.

The Trust Indenture gives to the Board of Directors the authority to exercise the rights, powers and privileges for all matters relating to the maximization of Unitholder value in the context of a take-over bid (an "Offer") including any Unitholder rights protection plan, any defensive action to an Offer, any directors circular in response to an Offer, any regulatory or court proceeding relating to an Offer and any related or ancillary matter.

Distributions and Distribution Policy

Cash distributions are made on the 15th day (or if such date is not a business day, on the preceding business day) following the end of each calendar month to Unitholders of record on the last business day of each such calendar month or such other date as determined from time to time by the Trustee.

The Board of Directors on our behalf reviews the distribution policy from time to time. The actual amount distributed will be dependent on various factors including the commodity price environment and is at the discretion of the Board of Directors of Penn West. The current distribution policy targets the use of approximately 60 percent to 70 percent of cash flow for distribution to Unitholders. Depending upon various factors including commodity prices and the size of Penn West's capital budget, it is expected that approximately 30 percent to 40 percent of cash flow will fund all or a portion of the Trust's annual capital expenditure program, including exploration, exploitation expenditures and minor property acquisitions, but excluding major acquisitions.

Distributions are normally announced on a monthly basis in the context of prevailing and anticipated commodity prices. During periods of volatile commodity prices, we may vary the distribution rate monthly.

Pursuant to the provisions of the Trust Indenture all taxable income earned by the Trust in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount is not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust Units in this period they will be allocated such income but will dispose of their right to receive the cash or Trust Units comprising such a distribution.

Directors and Officers

The name, municipality of residence, principal occupation for the prior five years and position, of each of the directors and officers of Penn West Petroleum Ltd. are as follows:

Directors

Name and Municipality of Residence	Director Since	Principal Occupation
James E. Allard(1) Calgary, Alberta, Canada	2006	Independent director and business advisor
William E. Andrew Calgary, Alberta, Canada	1994	President and Chief Executive Officer Penn West Petroleum Ltd.
George H. Brookman(1)(4)(5) Calgary, Alberta, Canada	2005	President and Chief Executive Officer of West Canadian Industries Group Inc.
John A. Brussa Calgary, Alberta, Canada	1995	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Jeffery E. Errico(3)(5) Calgary, Alberta, Canada	2006	Executive Chairman of Insignia Energy Inc., a private oil and natural gas company.
Murray R. Nunns(1)(2)(3)(5) Calgary, Alberta, Canada	2005	Executive Chairman of Monterey Exploration Ltd.
Thomas E. Phillips(1)(2)(3)(4)(5) Calgary, Alberta, Canada	1995	President, Newhaven Investments Inc. (oil and gas company).
Frank Potter(2)(4) Toronto, Ontario, Canada	2006	Chairman of Emerging Markets Advisors, Inc. (investment consulting firm)
James C. Smith(1)(3)(4)(5) Calgary, Alberta, Canada	2005	Independent director.

Notes:

(1) Member of audit committee.
(2) Member of human resources and compensation committee.
(3) Member of reserves committee.
(4) Member of the governance committee.
(5) Member of the health, safety and environment committee.

All of the directors have held the principal occupation set forth beside their name for the last five years except for the following: Murray R. Nunns, from 2002 to 2005, was President, Chief Executive Officer and Director of Crispin Energy Inc. and prior thereto held various management positions at Rio Alto Exploration Ltd. including Chief Operating Officer. Jeffery E. Errico was President and CEO of Petrofund Energy Trust since 2003 and President of Petrofund Energy Trust prior thereto, and James C. Smith who was also Chief Financial Officer of Mercury Energy Corporation, a private oil and natural gas company, from 2002 to 2006.

Each of the directors will hold office until the next annual meeting of Unitholders of the Trust or until their successors are elected or appointed.

Executive Officers

Name and Municipality of Residence	Office and Principal Occupation
William Andrew Calgary, Alberta, Canada	President and Chief Executive Officer
David Middleton Calgary, Alberta, Canada	Executive Vice President and Chief Operating Officer

Thane Jensen Calgary, Alberta, Canada	Senior Vice President, Exploration and Development
Todd Takeyasu Calgary, Alberta, Canada	Senior Vice President and Chief Financial Officer

William Tang Kong Calgary, Alberta, Canada	Senior Vice President, Corporate Development
Anne Thomson Calgary, Alberta, Canada	Vice President, Exploration
Eric Obreiter Calgary, Alberta, Canada	Vice President, Production
Gregg Gegunde Calgary, Alberta, Canada	Vice President, Development
Kristian Tange Calgary, Alberta, Canada	Vice President, Business Development
Lucas Law Calgary, Alberta, Canada	Vice-President, Asset Management
Keith Luft Calgary, Alberta, Canada	Vice-President, Land and Legal

The above appointments as officers were effective June 2005 except for William Tang Kong, Todd Takeyasu, Lucas Law and Keith Luft. In the preceding 5 years, the above officers held the principal occupations set forth except: David Middleton was Senior Vice President, Production since 2003 and prior thereto Vice President, Production since 2001; Thane Jensen was Vice President, Engineering since 2004 and prior thereto Manager, Exploitation since 2001; Todd Takeyasu was Vice President, Finance since 2005 and prior thereto Treasurer since 2001; William Tang Kong was Vice President, Corporate Development since 2005 and prior thereto Manager, Corporate Development since 2001; Anne Thomson was Manager, Exploration since 2003 and prior thereto District Geologist since 2001; Eric Obreiter was Manager, Production Central since 2001; Gregg Gegunde was Manager, Production Plains since 2003 and prior thereto Senior Engineer since 2001; Kristian Tange was Manager, Marketing since 2003 and prior thereto Manager, Natural Gas Marketing since 2001. Lucas Law was Manager, Corporate Development since 2005, Supervisor, Exploitation since 2004 and prior thereto Team Leader, Petrovera Resources since 2001. Keith Luft was Senior Solicitor, Conoco Phillips Canada Ltd./Burlington Resources Canada Ltd. since May 2004 and prior thereto a partner in a Calgary based law firm since 2001.

As at March 22, 2007, the directors and officers of Penn West Petroleum Ltd., as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 819,635 Trust Units or approximately 0.34 percent of the issued and outstanding Trust Units.

Corporate Cease Trade Orders or Bankruptcies

Except as otherwise disclosed herein, in the ten years preceding the date of this Annual Information Form, none of the proposed directors, officers or insiders of Penn West Petroleum Ltd. are or have been a director, officer or promoter of any other issuer that, while acting in such capacity:

(a) was the subject of a cease trade or similar order or an order that denied the issuer access to any statutory exemptions for a period of more than 30 consecutive days; or

(b) was declared bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy and insolvency or been subject to or instituted any proceedings, arrangement, or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of that person's stock.

John A. Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses. The reorganization resulted in the creation of two public corporations, Imperial Metals Corporation and IEI Energy Inc. (now Rider Resources Ltd.), both of which trade on the Toronto Stock Exchange.

James C. Smith was, from May 1999 to March 2000, Vice President and Chief Financial Officer of Probe Exploration Inc., an oil and gas company listed on the Toronto Stock Exchange. Mr. Smith joined Probe Exploration Inc. in order to assist management and the Board of

Directors of the company in their efforts to restructure the company's finances or sell assets to improve its financial situation. Such efforts did not succeed and the company's lender appointed a receiver in March 2000.

Penalties or Sanctions

None of the proposed directors, officers or insiders of Penn West Petroleum Ltd. have been subject to any penalties or sanctions under securities legislations except as disclosed herein.

Personal Bankruptcies

None of the directors, officers or insiders of Penn West Petroleum Ltd. have in the ten years preceding the date of this Annual Information Form become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold their assets except as disclosed herein.

Conflicts of Interest

The Board of Directors has adopted a Code of Business Conduct and Ethics and a Code of Ethics for Officers and Senior Financial Management (the "Codes"). In general, the private investment activities of employees, directors and officers are not prohibited, however, should an existing investment pose a potential conflict of interest the potential conflict is required by the Codes to be disclosed to the President and Chief Executive Officer or the Board of Directors. Any other activities posing a potential conflict of interest are also required by the Codes to be disclosed to the President and Chief Executive Officer or the Board of Directors. Any such potential conflicts of interests will be dealt with openly with full disclosure of the nature and extent of the potential conflicts of interests with the Trust.

It is acknowledged in the Codes that the directors may be directors or officers of other entities engaged in the oil and gas business, and that such entities may compete directly or indirectly with the Trust. Passive investments in public or private entities of less than one per cent of the outstanding shares will not be viewed as "competing" with the Trust. No executive officer or employee of Penn West should be a director or officer of any entity engaged in the oil and gas business unless expressly authorized by the Board of Directors. Any director of Penn West who is actively engaged in the management of, or who owns an investment of one per cent or more of the outstanding shares, in public or private entities shall disclose such holding to the Board of Directors. In the event that any circumstance should arise as a result of such positions or investments being held or otherwise which in the opinion of the Board of Directors constitutes a conflict of interest which reasonably affects such person's ability to act with a view to the best interests of the Trust, the Board of Directors will take such actions as are reasonably required to resolve such matters with a view to the best interests of the Trust. Such actions, without limitation, may include excluding such directors, officers or employees from certain information or activities of the Trust.

The *Business Corporations Act* (Alberta) provides that in the event that an officer or director is a party to, or is a director or an officer of or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction.

AUDIT COMMITTEE DISCLOSURES

Multilateral Instrument 52-110 ("MI 52-110") relating to audit committees has mandated certain disclosures for inclusion in this Annual Information Form. The text of the Audit Committee's mandate is attached as Appendix C to this Annual Information Form.

The members of the Audit Committee are James C. Smith, chairman, and James E. Allard, George H. Brookman, Murray R. Nunns and Thomas E. Phillips, each of whom is independent and financially literate within the meaning of MI 52-110. The following comprises a brief summary of each member's education and experience:

James C. Smith (Chairman)

Mr. Smith is a Chartered Accountant with over 30 years of experience in public accounting and industry. Since 1998, he has been a business consultant to a number of public and private companies operating in the oil and gas industry. From 2002 until its sale in 2006, he was also the Chief Financial Officer of Mercury Energy Corporation, a private oil and natural gas

company and from 2001 until the sale of the company in 2003, was the Chief Financial Officer of Segue Energy Corporation, a private oil and natural gas company. From 1999 to 2000, Mr. Smith was the Vice President and Chief Financial Officer of Probe Exploration Inc., a publicly traded oil and natural gas company. While Mr. Smith was the Vice President and Chief Financial Officer of Crestar Energy Inc. from its inception in 1992 until 1998, the company completed an initial public offering, was listed on the Toronto Stock Exchange and completed several major debt and equity financing transactions. Mr. Smith is currently a director of Grand Petroleum Inc., TAG Oil Ltd., Pure Energy Services Inc., and Grey Wolf Exploration Inc.

James E. Allard

Mr. Allard received his Bachelor of Science degree in Business Administration from the University of Connecticut and completed the Advanced Management Program at Harvard University. Mr. Allard has focused his career on international finance in the petroleum industry for the past 40 years serving as CEO, CFO and a director of a number of publicly traded and private companies. During the past seven years he served on the board of the Alberta Securities Commission, acting as the sole external trustee and advisor to a mid-sized pension plan and serves as a director and advisor to several companies. From 1981 to 1995, he served as a senior executive officer of Amoco Corporation as well as a director of Amoco Canada, then Canada's largest natural gas producer.

George H. Brookman

Mr. Brookman acquired West Canadian Industries Group in 1984 and under his leadership it has become one of Canada's largest privately held digital printing and imaging service companies.

He is also a partner in Vistek, a major retail camera operation with stores in Toronto, Calgary and one under construction in Edmonton and was the founder of Commonwealth Legal Inc., Canada's only national litigation support services operating in six Canadian cities. Prior to acquiring West Canadian Industries Group, Mr. Brookman was involved for many years in the commercial development industry in the Real Estate Group of Manulife and later as the Vice President of ATCO Development Ltd.

In addition to his thirty-five years of business experience, Mr. Brookman has been active in the community and is currently the Chairman elect of the Calgary Exhibition and Stampede. He is also on the advisory Board of the Department of Communications and Culture of the University of Calgary, a Director of KSPS Television in Spokane, Washington and Past President of the Rotary Club of Calgary.

Murray R. Nunns

Mr. Nunns is currently the Executive Chairman of Monterey Exploration Ltd. and is also a director of several other oil and gas companies in Western Canada including Capital Energy Ltd. and three additional private junior oil and natural gas companies. Mr. Nunns has over 25 years of experience with domestic and international oil and natural gas exploration and production activities. From 2003 to 2005, Mr. Nunns served as President, CEO and Director of Crispin Energy Inc. and from 1993 to 2002, held a variety of management positions at Rio Alto Exploration Ltd. including Executive Vice President of Exploration and Development and Chief Operating Officer. From 1986 to 1993, Mr. Nunns worked in several capacities with Unocal Exploration Ltd. including Chief Geologist for Unocal Canada and in portfolio management of its international exploration program. Mr. Nunns is a graduate of the University of Toronto and holds a Bachelor of Science (Honours) in Geology.

Thomas E. Phillips

Mr. Phillips is the President of Newhaven Investments Inc., a private company engaged in the acquisition, drilling and production of oil and natural gas in Alberta, and land development on the Sunshine Coast of British Columbia. He studied mathematics at the University of British Columbia and in 1976 received his Bachelor of Science degree from the University of Calgary with a major in geology and minor in computer science. He has worked at several companies including Home Oil, Placid Oil, and Placer CEGO and served as President of Albany Oil & Gas and Northern Reef Exploration Ltd. Mr. Phillips has been a Director of Penn West since 1995.

The terms of the engagement of Penn West's external auditors to provide audit services, including the budgeted fees for such audit services and the representations and disclaimer relating thereto, must be pre-approved by the entire Audit Committee.

With respect to any engagements of Penn West's external auditors for non-audit services, Penn West must obtain the approval of the Audit Committee or the Chairman of the Audit Committee prior to retaining the external auditors to complete such engagement. If such pre-approval is provided by the Chairman of the Audit Committee, the Chairman shall report to the Audit Committee on any non-audit service engagement pre-approved by him at the Audit Committee's first scheduled meeting following such pre-approval.

If, after using its reasonable best efforts, Penn West is unable to contact the Chairman of the Audit Committee on a timely basis to obtain the pre-approval contemplated by the preceding paragraph, Penn West may obtain the required pre-approval from any other member of the Audit Committee, provided that any such Audit Committee member shall report to the Audit Committee on any non-audit service engagement pre-approved by him at the Audit Committee's first scheduled meeting following such pre-approval.

The following is a summary of the fees paid to KPMG LLP for external audit and other services.

Audit Fees

The aggregate fees billed by our external auditor for audit services were:

2006 — $485,000

2005 — $215,000

Audit Related Fees

The aggregate fees billed by our external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements (not included in audit services fees) were:

2006 — $230,000

2005 — $187,500

Tax Fees

The aggregate fees billed by our external auditor for professional services for tax compliance, tax advice and tax planning were:

2006 — $18,341

2005 — $42,738

All Other Fees

The aggregate fees billed by our external auditor for products and services not included under the headings Audit Fees, Audit Related Fees and Tax Fees were:

2006 — $NIL

2005 — $NIL

DISTRIBUTIONS TO UNITHOLDERS

Since our formation as a trust, monthly cash distributions were declared in 2005 and 2006 in the following amounts, each amount being paid in the following month:

For the Month Ended	Distributions per Unit	
	2006	2005
January	$ 0.31	N/A
February	0.34	N/A
March	0.34	N/A
April	0.34	N/A
May	0.34	N/A
June	0.34	$ 0.26
July	0.34	0.26
August	0.34	0.26
September	0.34	0.26
October	0.34	0.31
November	0.34	0.31
December	0.34	0.31
Total	$ 4.05	$ 1.97

For Canadian income tax purposes, cash distributions paid to Unitholders in 2006 and 2005 were 100 percent taxable as other income.

MARKET FOR SECURITIES

The Trust Units are listed and traded on the Toronto Stock Exchange (“TSX”) under the symbol PWT.UN and on the New York Stock Exchange (“NYSE”) under the symbol PWE. The following tables set forth trading information for our Trust Units in 2006.

	TSX		
Period	Unit price ($) High	Unit price ($) Low	Volume
January	43.37	38.06	23,178,660
February	44.69	37.86	22,155,294
March	44.06	39.10	16,116,224
April	45.24	41.37	17,311,732
May	47.50	38.90	19,502,095
June	45.30	38.85	22,996,544
July	45.48	42.00	18,177,470
August	47.77	45.10	18,380,207
September	46.08	38.68	23,573,983
October	44.40	35.60	38,956,721
November	38.49	31.60	53,881,368
December	37.56	35.30	14,828,854

	NYSE		
Period	Unit price ($US) High	Unit price ($US) Low	Volume
June(1)	40.20	37.20	1,907,200
July	41.09	37.40	7,733,100
August	42.98	40.02	10,105,100
September	41.46	35.39	14,942,300
October	39.38	31.50	13,124,000
November	34.00	27.74	39,446,400
December	32.72	30.35	15,114,700

Note:

(1) Trading on NYSE began on June 22, 2006.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two years to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The governments of Alberta, British Columbia, and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are

determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1 percent effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the 2006 Federal Budget, the federal corporate income tax rate will decrease to 19 percent in three steps: 20.5 percent on January 1, 2008; 20 percent on January 1, 2009 and 19 percent on January 1, 2010.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil in "new oil" and "old oil" depending on when the oil pools were discovered. If discovered prior to March 31, 1974 is considered "old oil", if discovered after March 31, 1974 and before September 1, 1992, is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10 percent and a rate cap of 25 percent for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10 percent and a rate cap of 30 percent. The old oil royalty reserved to the Crown has a base rate of 10 percent and a rate cap of 35 percent.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15 percent and 30 percent, in the case of new natural gas, and between 15 percent and 35 percent, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2007, which, among other things, determines the Crown's share of crude and processed oil sands products.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("ARTC") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "IETP") which is intended to

promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications is May 31, 2007.

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, gas and oil sands will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process is to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees. The issues to be reviewed during this examination process are: (i) undertaking a comparison of Alberta's royalty system to other oil and gas producing jurisdictions, taking into account investment economics and industry returns and risks in Alberta; (ii) whether Alberta's royalty system is sufficiently sensitive to market conditions; (iii) whether the current revenue minus cost system for oil sands royalties is optimal; (iv) which programs built into the existing royalty system should be retained or strengthened, and which should be adapted or eliminated; (v) how the tax treatment of the oil and gas sector compares to other sectors and jurisdictions; (vi) the economic and fiscal impacts of any possible changes to the royalty and corporate tax structures; and (vii) how existing resource development should be treated if changes are to be made to the fiscal regime. The review panel is to produce a final report that will be presented to the Minister of Finance by August 31, 2007.

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and

extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("Strategy"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to $30 million annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. With regards to the oil and gas industry, the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishing of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the

research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth-tier oil" introduced October 1, 2002, "third-tier oil", "new oil", or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5 percent for all "fourth-tier oil" to 20 percent for "old oil". Marginal royalty rates are 30 percent for all "fourth-tier oil" to 45 percent for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth-tier gas" introduced October 1, 2002, "third-tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5 percent for "fourth-tier gas" and 20 percent for "old gas". The marginal royalty rates are between 30 percent for "fourth -tier gas" and 45 percent for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5 percent and a freehold production tax rate of zero percent.

- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("RTR") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to five years since the Government of Canada had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, the minimum

of which is two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation

also requires that wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "EPEA"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "OGCA"). The EPEA and OGCA impose stricter environmental standards; require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. No additional expenses are foreseen that are associated with complying with the new regulations. We anticipate making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. We believe that we will be in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process.

In December, 2002, the Government of Canada ratified the Kyoto Protocol that became legally binding on February 16, 2005. This protocol calls for Canada to reduce its greenhouse gas emissions to six percent below 1990 levels during the period between 2008 and 2012. The protocol is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of this protocol have yet to be announced, the effect on our operations cannot be determined at this time.

The Government of Canada has announced its intention to regulate greenhouse gases ("GHG") and other air pollutants. The Government is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce GHG emissions by 45 percent to 65 percent by 2050 and a commitment to regulate industry on an emissions intensity basis in the short-term. Currently there are few technical details regarding the implementation of the Government's plan to regulate industrial GHG emissions, but the Government has made a commitment to work with industry to develop the specifics.

The Alberta Government has also released draft regulations that will require facilities that emit over 100,000 tonnes of CO_2E/yr (total Greenhouse Gases in terms of CO_2 equivalent) to reduce their emissions intensity (quantity of gases releases per unit of production) by 12 percent starting July 1, 2007. Facilities that do not reduce their emissions intensity by this amount will either be charged $15/tonne for every tonne they are over the 12 percent target or they will have to invest in projects outside of their facility, but still in Alberta, that reduce or offset emissions on their behalf. Penn West currently does not operate any facilities that fall under the current regulations but it does have a working interest in some facilities that do. The full impact of this regulation is currently unknown but it is very likely that these targets will result in increased operating costs for facilities that are under these regulations. However, Penn West believes that this new regulation will be of overall benefit to the Trust as it will most likely result in increased interest in CO_2 capture and storage technologies and infrastructure that will increase the speed of development of its CO_2 injection plans in Pembina.

As the federal and provincial programs are under development, Penn West is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that we could face increases in operating costs in order to comply with GHG emissions legislation. However, Penn West in cooperation with the Canadian Association of Petroleum Producers will continue to work with the Government to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector. In the meantime, we will continue its current activities to reduce emissions intensity, improve energy efficiency and develop CO_2 injection and sequestration infrastructure. See "Risk Factors — Environmental" and "Risk Factors — Kyoto Protocol".

RISK FACTORS

The following is a summary of certain risk factors relating to our business which prospective investors should carefully consider before deciding whether to purchase Trust Units.

Volatility of Oil and Natural Gas Prices

Our operational results and financial condition of our operating entities and therefore the amounts paid to us will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by economic, and in the case of oil prices, also political factors. Supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions impact prices. Any movement in oil and natural gas prices will have an effect on our cash flow from operations, financial condition and therefore on our financial position and the cash available to be distributed to Unitholders. We may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If we hedge our commodity price exposure, we could forego the benefits we would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose us to cash and income losses. To the extent that we engage in risk management activities related to commodity prices, there are credit risks associated with counterparties with which we contract.

Variations in Foreign Exchange Rates and Interest Rates

World oil 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 that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our operating entities production revenues**.** The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact future distributions and the future value of our reserves as determined by independent evaluators.

To the extent that we engage in risk management activities related to foreign exchange rates, there is credit risk associated with counterparties with which we contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a decrease in distributions to Unitholders, as well as negatively impact the market price of the Trust Units.

Proposed Federal Tax Changes

On October 31, 2006 the Federal Minister of Finance proposed to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the unitholders (the "October 31 Proposals"). On December 21, 2006 the Federal Minister of Finance released draft legislation to implement the October 31, 2006 Proposals pursuant to which, commencing January 1, 2011 (provided Penn West only experiences "normal growth" and no "undue expansion" before then) certain distributions from us which would have otherwise been taxed as ordinary income generally will be characterized as dividends to the Unitholders and will be subject to tax at the corporate rates at the Trust level. Assuming the October 31 Proposals are ultimately enacted in their current form, the implementation of such legislation would be expected to result in adverse tax consequences to us and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact the level of cash distributions from us.

Management believes that the October 31 Proposals may reduce the value of the Trust Units, which would be expected to increase the cost to Penn West of raising capital in the public capital markets. In addition, management believes that the October 31 Proposals are expected to: (a) substantially eliminate any competitive advantage that Penn West and other Canadian energy trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner; and (b) place Penn West and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The October 31 Proposals are also expected to make the Trust Units less attractive as consideration for acquisitions. As a result, it may become more difficult for us to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize our legal and tax structure to substantially mitigate the expected impact of the October 31 Proposals.

Further, the proposals provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to us of that transitional period. As a result, the adverse tax consequences resulting from the proposals could be borne sooner than

January 1, 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by "normal growth" in this context. Specifically, the Department of Finance stated that "normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to a "specified investment flow-through's" ("SIFT") market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the SIFT's issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007, and 20 percent each for calendar year 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the Department of Finance's guidelines include the following:

(a) new equity for these purposes includes units and debt that is convertible into units (and may include other substitutes for equity if attempts are made to develop those);

(b) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures or otherwise, will not be considered growth for these purposes and will therefore not affect the safe harbour; and

(c) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for those purposes and will therefore not affect the safe harbour where the issuance of the trust units is made in satisfaction of the exercise of the exchange right by a person other than the SIFT.

Our market capitalization as of the close of trading on October 31, 2006, having regard only to our issued and outstanding publicly-traded Trust Units, was approximately $9.987 billion, which means our "safe harbour" equity growth amount for the period ending December 31, 2007 is approximately $3.996 billion, and for each of calendar year 2008, 2009 and 2010 is an additional approximately $1.998 billion (in any case, not including equity, including convertible debentures, issued to replace debt that was outstanding on October 31, 2006).

While these guidelines are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions.

The Government of Canada confirmed its intention to proceed with the October 31 Proposals, subject to any modifications to take into account consultations and deliberations, in its budget speech of March 19, 2007.

It is not known at this time when the October 31 Proposals will be enacted by Parliament, if at all, or whether the October 31 Proposals will be enacted in the form currently proposed or new proposals will be proposed or enacted. See "Risk Factors — Changes in Legislation".

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and cash flows to be derived therefrom, including many factors beyond our control. The reserve and associated cash flow information set forth in this Annual Information Form represents 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 natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative, and classifications of reserves are attempts to define the degree of speculation involved. 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 expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues and development and operating expenditures will vary from reserve estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are sometimes based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. 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, GLJ has used both constant and forecast price and cost estimates in calculating reserve quantities included in this Annual Information Form. Actual future net cash flows will be affected by other factors including but not limited to 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 reserves will vary from the reserves estimates contained in the engineering reports summarized in this Annual Information Form, and such variations could be material. The GLJ Report is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the engineering reports summarized in this Annual Information Form will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the engineering reports summarized in this Annual Information Form.

Depletion of Reserves

Distributions of income from our properties, absent commodity price increases or cost effective exploration, acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. As we distribute a portion of our cash flow to Unitholders, we will not be reinvesting cash flow in the same manner as some other industry participants and will only conduct limited exploratory activities as one of our main objectives is to maximize long-term distributions. Accordingly, absent capital injections, our initial production levels and reserves will decline over time and, absent changes to other factors, the level of income available for distributions will also decline over time.

Our future oil and natural gas reserves and production, and therefore our cash flows, will be highly dependent on our success in exploring and exploiting our reserve and land base and acquiring additional reserves. Without reserve additions through acquisition, exploration or development activities, our reserves and production will decline over time as our existing reserves are produced.

To the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. To the extent that we are required to use higher proportions of cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distributions will be reduced.

There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

Changes in Legislation

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

We intend to continue to qualify as a mutual fund trust for purposes of the *Income Tax Act* (Canada). We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders, including income generated by the royalties we hold. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax or hold their units in a tax deferred account.

- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if we ceased to be a mutual fund trust.

- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

- Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs") or deferred profit sharing plans. If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to one percent of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Revenue Agency.

In addition, we may take certain measures in the future to the extent we believe necessary to ensure that we maintain our status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the *Income Tax Act* (Canada).

On February 16, 2007, the Alberta government began a review of Alberta's royalty regime for oil sands, conventional oil and gas and coalbed methane to assess whether the existing royalty regime is providing Albertans with a fair return on the province's natural resources while maintaining an internationally competitive system that allows the Alberta economy to continue to prosper. The review, expected to be completed by August 31, 2007, may result in recommendations which could adversely impact the current royalty structure in place for our economics for our coalbed methane prospects. For more information, see "Risk Factors — Non-resident Ownership of Trust Units", "Risk Factors — Proposed Federal Tax Changes", "Risk Factors — Environmental Concerns" and "Risk Factors — Kyoto Protocol".

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 significant expenditures and a breach 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 our operating entities to incur costs to remedy such discharge. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. In particular there is uncertainty regarding the Government of Canada's Clean Air Act of 2006. The Clean Air Act proposes to reduce greenhouse gas emissions, however emission targets and compliance deadlines differ from those outlined in the Kyoto Protocol which was ratified by Canada. If passed, the Clean Air Act may have adverse operational and financial implications to the Trust. Provincial emission reduction requirements, such as those proposed in Alberta's Bill 37 Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity of our operations and facilities. The direct or indirect costs of these regulations may adversely and materially affect our business. Although we believe that we are 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 adversely affect our financial condition, results of operations or prospects. Future changes in other environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations. See "Industry Conditions — Environmental Regulation".

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse natural gases". Our exploration and production facilities and other operations and activities emit a small amount of greenhouse natural gases which may subject us to legislation regulating emissions of greenhouse natural gases. The Government of Canada has put

forward a Climate Change Plan for Canada that suggests further legislation will set greenhouse natural gases emission reduction requirements for various industrial activities, including oil and natural gas exploration and production. While the protocol became legally binding on February 16, 2005, details of any specific requirements have not been released and as a result the potential impact on our operations and business is difficult to quantify. See “Industry Conditions — Environmental Regulation”.

Resource Plays — Enhanced Oil Recovery

We currently use conventional artificial lift technology to recover heavy oil from bitumen deposits at our Peace River Oil Sands project. The potential or planned use of enhanced oil recovery (“EOR”) methods such as steam injection (Steam Assisted Gravity Drainage and Cyclical Steam Stimulation), solvent injection and firefloods to increase the ultimate recovery of oil resources in place are subject to significant risk factors. These factors, which could lead to delayed or cancelled EOR application in the Peace River Oil Sands project include but are not limited to the following: (i) changing economic conditions (commodity pricing, operating and capital expenditure fluctuations); (ii) changing engineering and technical conditions (ability to apply EOR methods to the reservoir and the production response thereto); (iii) the large development program may need to spread over a longer time period than initially planned due to requirement to allocate capital expenditures to different periods; (iv) surface access and deliverability issues (First Nations relations, weather, pipeline, road and processing matters); and (v) financing (the availability of sufficient financing on acceptable terms).

The use or potential or planned use of CO_2 miscible flooding to increase the oil recovery from large legacy oil pools such as Pembina, South Swan Hills and Midale is subject to significant risk factors which could lead to the delay or cancellation of some or all of these projects. These factors include but are not limited to: (i) CO_2 infrastructure (the capture and transportation of the miscible agent to us at an economic cost); (ii) changing economic conditions (commodity pricing, operating and capital expenditure fluctuations); (iii) changing engineering and technical conditions (ability to apply CO_2 EOR methods to the reservoir and the production response thereto); (iv) the large development program may need to be spread over a longer time period than planned due to capital allocation requirements; (v) surface access and deliverability issues (weather, pipeline, road and processing matters); and (vi) financing (the availability of sufficient financing on acceptable terms).

Coalbed Methane Projects (“CBM”)

The engineering, geological, production and associated dewatering techniques are relatively new and their application to our CBM prone properties is subject to these risks in addition to risk factors similar to those listed in the preceding paragraphs related to the Peace River Oil Sands and CO_2 miscible flooding.

Additional Financing

In the normal course of making capital investments to maintain and expand our oil and gas reserves, additional Trust Units may be issued which may result in a decline in production per Trust Unit and reserves per Trust Unit. Additionally, from time to time, we may issue Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure. Conversely, to the extent that external sources of capital, including the issuance of additional Trust Units becomes limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and gas reserves will be impaired. Management believes that the October 31 Proposals of the Government of Canada are expected to substantially eliminate the competitive advantage that we and other energy trusts enjoy relative to their industry competitors in raising capital in a tax-efficient manner. See “Risk Factors — Proposed Federal Tax Changes”. To the extent that we are required to use additional cash flow to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of cash flow for distributions will be reduced.

Competition

There is strong competition relating to all aspects of the oil and gas industry. There are numerous trusts and conventional exploration and production companies in the oil and gas industry, who are also competing for the acquisitions of properties with longer life reserves and properties with exploitation and development opportunities. The October 31 Proposals of the Government of Canada are expected by management to make our Trust Units less attractive as consideration for acquisitions. See “Risk Factors — Proposed Federal Tax Changes”. As a result of such increasing competition, it is expected to become more difficult to acquire producing assets and reserves on beneficial terms. We also compete for skilled industry personnel with a substantial number of other oil and gas companies and trusts.

Non-Resident Ownership of Trust Units

In order for us to maintain our status as a mutual fund trust under the *Income Tax Act* (Canada), we must not be established or maintained primarily for the benefit of non-residents of Canada (“non-residents”) within the meaning of the *Income Tax Act* (Canada). The Trust Indenture provides that the Trust will use its best commercial efforts to maintain its status as a mutual fund trust under the *Income Tax Act* (Canada). See “Information Relating to the Trust — Trust Indenture — Limitations on Non-Resident Ownership”. Generally speaking, the *Income Tax Act* (Canada) provides that a trust will permanently lose its

“mutual fund trust” status (which is essential to the income trust structure) if it is established or maintained primarily for the benefit of non-residents of Canada (which is generally interpreted to mean that the majority of unitholders must not be non-residents of Canada), unless at all times after February 21, 1990, “all or substantially all” of the trust’s property consisted of property other than taxable Canadian property (the “TCP Exception”). Based on the most recent information obtained by Penn West through its transfer agent and financial intermediaries, in February

2007, we have estimated that in excess of 50% of the Trust's issued and outstanding Trust Units were held by non-residents of Canada (as defined in the *Income Tax Act* (Canada)) at that time. The Trust has determined that it currently meets the requirement of the TCP Exception, and as a result, the Trust Indenture does not currently have a specific limit on the percentage of Trust Units that may be owned by non-residents.

There is no assurance that the TCP Exception will continue to be available to the Trust or that the Government of Canada will not introduce new changes or proposals to tax regulations directed at non-resident ownership which, given the Trust's level of non-resident ownership, may result in the Trust losing its mutual fund trust status or could otherwise detrimentally affect Penn West and the market price of the Trust Units. Penn West Petroleum Ltd. intends to continue to take the necessary measures in order to ensure the Trust continues to qualify as a mutual fund trust under the *Income Tax Act* (Canada), as it currently exists. See "Risk Factors — Changes in Legislation".

Debt Service

Amounts paid in respect of interest and principal on debt we have incurred will reduce funds available for distributions. Variations in interest rates and any scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the NPIs. Certain covenants in the agreements with our lenders may also limit distributions in certain circumstances. Increases in interest rates could also result in decreases to the market value of our Trust Units, although we believe our credit facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations or that additional funds will be able to be obtained.

Our current credit agreement is unsecured and we must comply with certain financial debt covenants. The lenders could, in the future, be provided with security over substantially all of our assets. In that event 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 our oil and gas and other assets.

Asset Write-Downs

Canadian Generally Accepted Accounting Principles ("GAAP") require that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in our consolidated financial statements.

Under GAAP, the amounts at which petroleum and natural gas property and equipment are carried as net assets on the balance sheet are subject to a cost-recovery or "ceiling" test, which is based in part upon estimated future net cash flows from reserves. If net capitalized costs exceed the estimated recoverable amounts, we will have to charge the amount of the excess to net income. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings. The value of oil and gas properties is highly dependent upon the prices of oil and natural gas. Under United States GAAP, the estimated recoverable amounts are calculated based on estimated future net cash flows from proved reserves discounted at ten percent and using commodity prices in effect on the balance sheet date. The use of discounting and constant prices results in a greater likelihood of a write down under United States GAAP than Canadian GAAP. See "Risk Factors — Volatility of Oil and Natural Gas Prices".

GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the Trust Unit price may indicate goodwill impairment. As at December 31, 2006 we had $652 million recorded on our balance sheet as goodwill arising out of the Petrofund Merger. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions.

GAAP in respect of accounting for financial instruments may result in non-cash charges against income as a result of changes in the fair market value of hedging instruments. A decrease in the fair market value of the hedging instruments as the result of fluctuations in commodity prices and/or foreign exchange rates may result in a non-cash charge against income. Such non-cash charges may be temporary in nature if the fair market value subsequently increases.

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 that may be amended from time to time. See "Industry Conditions". Our operations may require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at our projects.

Operational Matters

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks. Losses resulting from the occurrence of these risks could have a material adverse impact on us. Like other oil and natural gas trusts and companies, we attempt to conduct our business and financial affairs so as to protect against political and economic risks applicable to operations in the jurisdictions where we operate but there can be no assurance that we will be successful in so protecting our assets.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Operating costs on most properties have increased steadily over recent years. To the extent the operator fails to perform these functions properly, operating income 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 our claim to certain of our oil and gas properties. A reduction of the income available for distributions could result in such circumstances.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties could subject Penn West to liability for pollution, blowouts, property damage, personal injury or other hazards. Prior to commencing operations our operating entities obtain insurance in accordance with industry standards to address certain of these risks. Such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances, be insurable or, in certain circumstances, our operating entities 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 such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects and will reduce cash flow otherwise distributable by us.

Maintenance of Distributions

Future oil and natural gas reserves and hence revenues are highly dependent on our operating entities' success in exploiting existing properties and acquiring additional reserves. We also distribute approximately 60 percent to 70 percent of our net cash flow to Unitholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our operating entities' ability to make the necessary capital investments to maintain or expand their oil and natural gas reserves will be impaired. To the extent that our operating entities are required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to Unitholders will be reduced. Additionally, we cannot guarantee that we will be successful in exploring for and developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of Trust Units and in a reduction in cash available for distributions to Unitholders.

Delay in Cash Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our operating entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other

accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses.

Reliance on Management

Unitholders will be dependent on the management of Penn West Petroleum Ltd. in respect of the administration and management of all matters relating to our operations. Penn West Petroleum Ltd., as of December 31, 2006, operated approximately 70 percent of our total daily production. Investors who are not willing to rely on the management of Penn West Petroleum Ltd. should not invest in the Trust Units, or any future issuance of exchangeable shares and/or convertible debentures.

Expansion of Operations

The operations and expertise of management are currently focused on conventional oil and gas production and exploration 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 Trust Indenture does not limit our activities to oil and gas production and development, and we could acquire other energy related assets, such as additional oil and natural gas processing plants, upgrades or pipelines. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors that may result in our future operational and financial conditions being adversely affected.

Net Asset Value

Our net asset value from time to time will vary depending upon a number of factors beyond the control of management, including oil and gas prices. The trading prices of the Trust Units from time to time are also determined by a number of factors some of which are beyond the control of management and such trading prices may be greater or less than our net asset value.

Return of Capital

Trust Units will have no value when the underlying petroleum and natural gas properties can no longer be economically produced and, as a result, cash distributions may not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Distributions can represent a *return of* or a *return on* Unitholders capital.

Unitholders have a limited right to require us to repurchase their Trust Units, which is referred to as a redemption right. See "Information Relating to the Trust — Trust Indenture — Right of Redemption". It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not

develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

Nature of Trust Units

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in Penn West Petroleum Ltd. The Trust Units represent a fractional interest in our assets. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and in some cases the *Winding Up and Restructuring Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation. Our sole assets will be the NPIs and other investments in securities of our operating entities including the Notes. The price per Trust Unit is a function of anticipated income available for distributions, the oil and gas assets acquired by us and our ability to effect long-term growth in the value of our assets. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, we are not a trust company and, accordingly, the Trust is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with our obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on our behalf must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against us that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force.

Our operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Unitholders for claims against us.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but are still material and are still in effect, are the following:

(a) the Trust Indenture;
(b) the Administration Agreement; and
(c) the NPI Agreements.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Trust Units is CIBC Mellon Trust Company at its principal offices in Calgary, Alberta.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of Penn West Petroleum Ltd., any holder of Trust Units who beneficially owns more than 10 percent of the outstanding Trust Units, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years which has materially affected or would materially affect us except for the matter disclosed in Note 17 under the heading "Related party transactions" of the consolidated financial statements for the years ending 2006 and 2005 which note is incorporated by reference in this Annual Information Form and which is filed on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator, and KPMG LLP, our auditors. As at the date hereof the designated professionals of GLJ Petroleum Consultants Ltd., as a group, beneficially owned, directly or indirectly, less than 1 per cent of our outstanding securities, including the securities of our associates and affiliates. KPMG LLP is the auditor of the Trust and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants, Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Penn West Petroleum Ltd. or of any of our associate or affiliate entities. John A. Brussa, the Chairman of Penn West Petroleum Ltd., is a partner at Burnet, Duckworth & Palmer LLP, a law firm which renders legal services to us.

ADDITIONAL INFORMATION

Additional information including remuneration of directors and officers of Penn West Petroleum Ltd., principal holders of the Trust Units and rights to purchase Trust Units, will be contained in the Information Circular which relates to the Annual Meeting of Unitholders to be held on June 8, 2007, and additional financial information is provided in our consolidated financial statements and management discussion and analysis of financial results for the year ended December 31, 2006 which have been filed on SEDAR at *www.sedar.com*.

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

(Form 51-101F3)

Management of Penn West Petroleum Ltd. on behalf of Penn West Energy Trust (collectively "Penn West") is responsible for the preparation and disclosure of information with respect to Penn West's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated Penn West's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors has:

(a) reviewed Penn West's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed Penn West's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

/s/ William E. Andrew
President and Chief Executive Officer

/s/ David Middleton
Executive Vice President and Chief Operating Officer

/s/ Murray Nunns
Director and Chairman of the Reserves Committee

/s/ Thomas E. Philips
Director and Member of the Reserves Committee

March 22, 2007

APPENDIX B

GLJ REPORT ON RESERVES DATA

(Form 51-101 F2)

To the Board of Directors of Penn West Petroleum Ltd. on behalf of Penn West Energy Trust (collectively "Penn West"):

1. We have evaluated Penn West's reserves data as at December 31, 2006. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of Penn West's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Penn West evaluated and reviewed by us for the year ended December 31, 2006, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to Penn West's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (millions before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	February 28, 2007	Canada	nil	$ 7,049	nil	$ 7,049

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

/s/ GLJ Petroleum Consultants Ltd.
Calgary, Alberta
February 28, 2007

APPENDIX C

MANDATE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors of Penn West Petroleum Ltd. (the " **Company**"), administrator of Penn West Energy Trust (the "**Trust**"), to which the board has delegated its responsibility for oversight of the integrity of the Trust's consolidated financial statements, the Trust's compliance with legal and regulatory requirements, the independent auditor's qualifications and independence,

and the performance of the Trust's internal audit function, if any. The objectives of the Committee, with respect to Company and the Trust (hereinafter collectively referred to as "**Penn West**"), are as follows:

- To assist the Board in meeting its responsibilities (especially for accountability) in respect of the preparation and disclosure of the consolidated financial statements of the Trust and related matters;
- To provide better communication between directors and independent auditors;
- To assist the Board in meeting its responsibilities regarding the oversight of the independent auditor's qualifications and independence;
- To assist the Board in meeting its responsibilities regarding the oversight of the credibility, integrity and objectivity of financial reports;
- To strengthen the role of the non-management directors by facilitating discussions between directors on the Committee, management and independent auditors;
- To assist the Board in meeting its responsibilities regarding the oversight of the performance of the Company's independent auditors and internal audit function, if any; and
- To assist the Board in meeting its responsibilities regarding the oversight of the Company's compliance with legal and regulatory requirements.

Mandate and Responsibilities of Committee

- It is the responsibility of the Committee to satisfy itself on behalf of the Board that the Company's internal control systems are sufficient to reasonably ensure that:
  - controllable, material business risks are identified, monitored and mitigated where it is determined cost effective to do so;
  - internal controls over financial reporting are sufficient to meet the requirements under MI 52-109 and the United States Securities Exchange Act of 1934, as amended, and
  - legal, ethical and regulatory requirements are complied with.
- It is a primary responsibility of the Committee to review the annual and quarterly financial statements of the Trust prior to their submission to the board of directors for approval. The process should include but not be limited to:
  - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
  - reviewing accounting treatment of unusual or non-recurring transactions;
  - reviewing the Trust's status as a "mutual fund trust" under the *Income Tax Act* (Canada);

  - ascertaining compliance with covenants under loan agreements and Trust Indenture;
  - reviewing adequacy of the asset retirement obligations;
  - reviewing disclosure requirements for commitments and contingencies;
  - reviewing adjustments raised by the independent auditors, whether or not included in the financial statements;
  - reviewing unresolved differences between management and the independent auditors, if any;
  - obtaining reasonable explanations of significant variances with comparative reporting periods; and
  - determine through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed.
- The Committee is to review, discuss and recommend for approval by the Board the annual and quarterly financial statements and related information included in prospectuses, management discussion and analysis (MD&A), information circular-proxy statements and annual information forms (AIF), prior to recommending board approval.
- Discuss the Trust's quarterly results press releases, as well as financial information and earnings guidance provided to analysts and rating agencies (provided that the Committee is not required to review and discuss investor presentations that do not contain financial information or earnings guidance that has not previously been generally disclosed to the public).
- With respect to the appointment of independent auditors by the Board, the Committee shall:
  - on an annual basis, the Committee shall review and discuss with the auditors all relationships the auditors have with the Trust and the Company to determine the auditors' independence. In addition, the Committee will ensure the rotation of partners on

the audit engagement team in accordance with applicable law and, in order to ensure continuing auditor independence, consider the rotation of the audit firm itself;

- be directly responsible for appointing, compensating, retaining and overseeing the work of the independent auditors engaged for the purpose of issuing an auditors' report or performing other audit, review or attest services for the Trust, including the resolution of disagreements between management and the independent auditor regarding financial reporting, and the independent auditors shall report directly to the Committee;
- review and evaluate the performance of the lead partner of the independent auditors;
- review the basis of management's recommendation for the appointment of independent auditors and recommend to the board appointment of independent auditors and their compensation;
- review the terms of engagement and the overall audit plan (including the materiality levels to be applied) of the independent auditors, including the appropriateness and reasonableness of the auditors' fees;
- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
- review and pre-approve any audit and permitted non-audit services to be provided by the independent auditors' firm and consider the impact on the independence of the auditors.

- At least annually, obtaining and reviewing the report by the independent auditors describing the independent auditors' internal quality control procedures, any material issues raised by the most recent interim quality-control review, or peer review, of the independent auditors, or by any inquiry or

investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the independent auditors, and any steps taken to deal with any such issues.

- Review with the independent auditors (and internal auditors, if any) their assessment of the internal controls of the Company, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the independent auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Penn West and its subsidiaries.
- At least annually, obtaining and reviewing a report by the independent auditors describing (i) all critical accounting policies and practices used by the Trust, (ii) all alternative accounting treatments of financial information within generally accepted accounting principles related to material items that have been discussed with management, including the ramifications of the use of such alternative treatments and disclosures and the treatment preferred by the accounting firm, and (iii) other material written communications between the accounting firm and management of Penn West.
- Obtain assurance from the independent auditors that disclosure to the Committee is not required pursuant to the provisions of the United States Securities Exchange Act of 1934, as amended, regarding the discovery by the independent auditors of illegal acts.
- Pre-approve the completion of any audit and permitted non-audit services by the independent auditors and determine which non-audit services the independent auditor is prohibited from providing. The Committee may delegate to one or more members of the Committee authority to pre-approve non-audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Committee member to whom authority has been delegated must be presented to the Committee at its first scheduled meeting following such pre-approval. The Committee shall be entitled to adopt specific policies and procedures for the engagement of non audit services if:
  - the pre-approval policies and procedures are detailed as to the particular service;
  - the Committee is informed of each non-audit service so approved; and
  - the procedures do not include delegation of the Committee's responsibilities to management.
- The Committee will satisfy the pre-approval requirement set forth in the above paragraph if:
  - the aggregate amount of all non audit services that were not pre approved is reasonably expected to constitute no more than 5% of the total amount of fees paid by the Trust and its subsidiary entities to the auditors during the fiscal year in which the services are provided;
  - the Trust or the subsidiary entity, as the case may be, did not recognize the services as non-audit services at the time of the engagement;
  - the services are promptly brought to the attention of the Committee and approved, prior to completion of the audit, by the Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Committee; and
- Review, set and approve hiring policies relating to current and former staff of current and former independent auditors.

- Review all public disclosure containing financial information before release (provided that the Committee is not required to review investor presentations that do not contain financial information or earnings guidance that has not previously been generally disclosed to the public).

- Review all pending litigation to ensure disclosures are sufficient and appropriate.

- Satisfy itself that adequate procedures are in place for the review of the Trust's public disclosure of financial information from the Trust's financial statements and periodically assess the adequacy of those procedures.

- Review and discuss major financial risk exposures and the steps management has taken to monitor and control such exposures. Discuss guidelines and policies to govern the process by which risk assessment and management is undertaken.

- Establish procedures independent of management for:

  - the receipt, retention and treatment of complaints received by the Trust regarding accounting, internal accounting controls, or auditing matters; and

  - the confidential, anonymous submission by employees of the Trust of concerns regarding questionable accounting or auditing matters.

- Review any other matters required by law, regulation or stock exchange requirement, or that the Committee feels are important to its mandate or that the Board chooses to delegate to it.

- Establish, review and update periodically a Code of Business Conduct and Ethics and the Code of Conduct for Senior Officers and Senior Financial Management and ensure that management has established systems to enforce these codes.

- Review management's monitoring of the Trust's compliance with the organization's Code of Business Conduct and Ethics and the Code of Conduct for Senior Officers and Senior Financial Management.

- Review and discuss with the CEO, the CFO and the independent auditors, the matters required to be reviewed with those persons in connection with any certificates required by applicable laws, regulations or stock exchange requirements to be provided by the CEO and CFO.

- Review and discuss major issues regarding accounting principles and financial statement presentations, including any significant changes in the Trust's selection or application of accounting principles.

- Review and discuss major issues as to the adequacy of the Trust's internal controls and any special audit steps adopted in light of material control deficiencies.

- Review and discuss analyses prepared by management and/or the independent auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative generally accepted accounting principles methods on the financial statements.

- Review and discuss the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the Trust's financial statements.

- Review and discuss the type and presentation of information to be included in earnings press releases, paying particular attention to any use of "pro forma" or "adjusted" non-GAAP information.

Composition

- This Committee shall be composed of at least three individuals appointed by the Board from amongst its members, all of which members will be independent (within the meaning of (a) Multilateral Instrument 52-110 Audit Committees and (b) Sections 303A.02 and 303A.07(b) of the Corporate Governance Rules of the New York Stock Exchange) unless the Board determines to rely on an exemption in NI 52-110.

- The Secretary to the Board shall act as Secretary of the Committee.

- A quorum shall be a majority of the members of the Committee.

- All of the members must be financially literate within the meaning of NI 52-110 and Section 303A.07(a) of the Corporate Governance Rules of the New York Stock Exchange unless the Board has determined to rely on an exemption in NI 52-110. Being "financially literate" means members have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected

to be raised by the Trust's financial statements. In addition, at least one member of the Committee must have accounting or related financial management expertise, as the Board interprets such qualification in its business judgment.

- In connection with the appointment of the members of the Committee, the Board will determine whether any proposed nominee for the Committee serves on the audit committee of more than three public companies. To the extent that any proposed nominee of PWPL serves on the audit committee of more than three public companies, the Board will make a determination as to whether such simultaneous services would impair the ability of such member to effectively serve on the Company's Audit Committee and will disclose such determination in the Trust's annual information circular and annual report on Form 40-F filed with the Securities and Exchange Commission.

Meetings

- The Committee shall meet at least four times per year and/or as deemed appropriate by the Committee Chair. As part of its job to foster open communication, the Committee should meet at least annually with management, internal auditors (if any) and the independent auditors in separate executive sessions to discuss any matters that the Committee or each of these groups believe should be discussed privately. In addition, the Committee or at least its Chair should meet with the independent auditors and management quarterly to review the Trust's financials. The Committee should also meet with management and independent auditors on an annual basis to review and discuss annual financial statements and the management's discussion and analysis of financial conditions and results of operations.

- Agendas, with input from management, shall be circulated to Committee members and relevant management personnel along with background information on a timely basis prior to the Committee meetings.

- Minutes of each meeting shall be prepared by the Secretary to the Committee.

- The Chief Executive Officer and the VP Finance or their designates shall be available to attend at all meetings of the Committee upon the invitation of the Committee.

- The Controller, Treasurer and such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee.

Reporting / Authority

- At the first Board meeting following a Committee meeting, the Committee will provide a verbal report to the Board of the material matters discussed and material resolutions passed at the Committee meeting. The draft minutes of the Committee meeting will subsequently be provided to all Board members as soon as practicable.

- Supporting schedules and information reviewed by the Committee shall be available for examination by any Director.

- The Committee shall have the authority to investigate any financial activity of the Trust and to communicate directly with the internal (if any) and independent auditors. All employees are to cooperate as requested by the Committee.

- The Committee may retain, and set and pay the compensation for, persons having special expertise and/or obtain independent professional advice, including the engagement of independent counsel and other advisors, to assist in fulfilling its duties and responsibilities at the expense of Penn West.

- The Committee may delegate any of its duties and responsibilities hereunder to the Committee Chair or any group of members of the Committee.

- The Committee, in its capacity as a committee of the Board, shall determine appropriate funding and cause such funding to be available (i) to Penn West's independent auditors for the purpose of preparing and issuing an audit report, (ii) to any advisors employed by the Committee, and (iii) for ordinary administration expenses of the Committee that are necessary or appropriate in carrying out its duties.

PENN WEST ENERGY TRUST

Management's Discussion & Analysis and Audited Consolidated Financial Statements

For the year ended December 31, 2006

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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 (when filed), 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

	Three months ended December 31		Year ended December 31	
($ millions, except per unit amounts)	**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 lead 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.

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 CO_2 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 its 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:

	Current System		Proposed System	
Investor	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) 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		
Daily Production	2006	2005	% change	2006	2005	% change
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 ($/bbl):						
Sales price	**$ 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 ($/bbl):						
Sales price	**$ 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 ($/bbl):						
Sales price	**$ 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

	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 2006	2005	% change	Year ended December 31 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 2006	2005	Year ended December 31 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.

CO_2 pilot costs represent capital expenditures related to the Pembina CO_2 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, 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, we increased our reserve life index and technological access to, and staff with experience in, resource plays including the Weyburn CO_2 project and coalbed methane.

Our farm-out program is ongoing; since 2005, 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

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 (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.

	Three months ended December 31		Year ended December 31	
($ millions, except per unit amounts)	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 USD$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)			Impact on Cash Flow (1)		Impact on Net Income (1)	
Change of	Change		$ millions	$/unit	$ millions	$/unit
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 ($USD 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 ($USD)	**2.5**	2.3	2.3	2.3	2.3	8.6
Power infrastructure	**4.6**	3.7	3.7	3.7	3.7	7.6
Drilling rigs	**6.9**	7.7	2.4	1.2	—	—
Purchase obligations (1)	**13.2**	13.3	13.3	13.3	13.3	54.3
Office lease	**$ 12.0**	$ 17.9	$ 17.5	$ 15.1	$ 14.3	$ 117.5

(1) These amounts represent estimated commitments of $95.5 million for CO_2 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.

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; the timing for beginning carbon dioxide injection at the Joffre Viking Unit; 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 CO_2 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 CO_2 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 farmout 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 (when filed), is available on SEDAR at www.sedar.com.

Exhibit 99.3

MANAGEMENT'S REPORT

The consolidated financial statements of Penn West Energy Trust were prepared by management in accordance with accounting principles generally accepted in Canada. In preparing the consolidated financial statements, management has made estimates because a precise determination of certain assets and liabilities is dependent on future events. The financial and operating information presented in this report is consistent with that shown in the consolidated financial statements.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of relevant, reliable and timely financial records for the preparation of statements.

The consolidated financial statements have been examined by the external auditors and approved by the Board of Directors. The Board of Directors' financial statement related responsibilities are fulfilled through the Audit Committee. The Audit Committee is composed entirely of independent directors. The Audit Committee recommends appointment of the external auditors to the Board of Directors, ensures their independence, and approves their fees. The Audit Committee meets regularly with management and the external auditors to discuss reporting and control issues and to ensure each party is properly discharging its responsibilities. The auditors have full and unrestricted access to the Audit Committee to discuss their audit and their related findings as to the integrity of the financial reporting process.



William E. Andrew
President and CEO



Todd H. Takeyasu
Senior Vice President and CFO



Derek W. Loomer
Controller

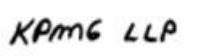
February 28, 2007

AUDITORS' REPORT TO THE UNITHOLDERS

We have audited the consolidated balance sheets of Penn West Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Chartered Accountants
Calgary, Canada

February 28, 2007

CONSOLIDATED BALANCE SHEETS

($ millions)	As at December 31 2006	2005
ASSETS		
Current		
Accounts receivable	**$ 268.7**	$ 214.4
Risk management (note 12)	**54.0**	8.5
Other	**56.0**	29.0
	378.7	251.9
Property, plant and equipment (note 4)	**7,039.0**	3,715.2
Goodwill (note 5)	**652.0**	—

	7,691.0	3,715.2
	$ 8,069.7	$ 3,967.1
LIABILITIES AND UNITHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	**$ 382.9**	$ 304.1
Taxes payable	**1.2**	11.8
Distributions payable	**80.6**	50.6
Deferred gain on financial instruments (note 12)	**—**	11.9
	464.7	378.4
Bank loan (note 6)	**1,285.0**	542.0
Asset retirement obligations (note 7)	**339.1**	192.4
Future income taxes (note 8)	**792.6**	682.1
	2,416.7	1,416.5
Unitholders' equity		
Unitholders' capital (note 9)	**3,712.4**	561.0
Contributed surplus (note 9)	**16.4**	5.5
Retained earnings	**1,459.5**	1,605.7
	5,188.3	2,172.2
	$ 8,069.7	$ 3,967.1

Subsequent event (note 18)

See accompanying notes to the audited consolidated financial statements.

Approved on behalf of the Board:



John A. Brussa
Chairman



James C. Smith
Director

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS

($ millions, except per unit amounts)	**Year ended December 31 2006**	**2005**
Revenues		
Oil and natural gas	**$ 2,100.9**	$ 1,919.0
Royalties	**(373.3)**	(355.0)
Risk management (note 12)	**42.8**	(14.8)
	1,770.4	1,549.2
Expenses		
Operating	**426.3**	327.4
Transportation	**24.5**	22.7
General and administrative	**36.0**	23.1
Financing	**49.3**	23.2
Depletion, depreciation and accretion (note 4)	**654.7**	437.6
Equity-based compensation (note 10)	**11.3**	77.2
Foreign exchange loss	**—**	4.5
Risk management activities (note 12)	**(5.8)**	(11.4)
	1,196.3	904.3
Income before taxes	**574.1**	644.9
Taxes		
Capital	**14.7**	14.7
Current income taxes	**—**	54.1
Future income tax recovery (note 8)	**(106.2)**	(1.1)
	(91.5)	67.7
Net income	**$ 665.6**	$ 577.2
Retained earnings, beginning of period	**$ 1,605.7**	$ 1,393.7
Net income	**665.6**	577.2
Trust conversion costs	**—**	(32.9)
Distributions declared	**(811.8)**	(321.5)
Dividends declared	**—**	(10.8)
Retained earnings, end of period	**$ 1,459.5**	$ 1,605.7
Net income per unit		
Basic	**$ 3.32**	$ 3.55
Diluted	**$ 3.27**	$ 3.48

See accompanying notes to the audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

($ millions)	Year ended December 31 2006	2005
Operating activities		
Net income	**$ 665.6**	$ 577.2
Depletion, depreciation and accretion (note 4)	**654.7**	437.6
Future income tax recovery	**(106.2)**	(1.1)
Unrealized foreign exchange loss	**—**	4.5
Equity-based compensation (note 10)	**11.3**	77.2
Risk management (note 12)	**(48.6)**	3.4
Payments for surrendered options	**—**	(141.6)
Asset retirement expenditures	**(26.9)**	(22.6)
Change in non-cash working capital (note 15)	**(43.6)**	(1.8)
	1,106.3	932.8
Investing activities		
Additions to property, plant and equipment, net	**(577.9)**	(456.7)
Petrofund merger costs	**(25.0)**	—
Change in non-cash working capital (note 15)	**11.7**	(63.2)
	(591.2)	(519.9)
Financing activities		
Increase (decrease) in bank loan	**132.6**	(51.4)
Issue of equity	**118.6**	23.7
Distributions/dividends paid	**(781.8)**	(288.4)
Trust conversion costs	**—**	(36.3)
Realized foreign exchange gain	**—**	85.8
Settlement of future income tax liabilities on trust conversion	**15.5**	(146.3)
	(515.1)	(412.9)
Change in cash	**—**	—
Cash, beginning of period	**—**	—
Cash, end of period	**$ —**	$ —
Interest paid	**$ 44.4**	$ 22.9
Income and capital taxes paid	**$ 8.6**	$ 241.2

See accompanying notes to the audited consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(All tabular amounts are in $ millions except numbers of units, per unit amounts, percentages and various figures in Note 12.)

1. Structure of the Trust

On May 31, 2005, Penn West Petroleum Ltd. (the "Company") was reorganized into Penn West Energy Trust ("Penn West" or the "Trust") under a plan of arrangement entered into by Penn West and the Company and its shareholders. Shareholders received three trust units for each common share held. On June 2, 2005, the trust units commenced trading on the TSX under the symbol "PWT.UN". On June 30, 2006, the trust units commenced trading on the NYSE under the symbol "PWE". The Trust was created pursuant to a trust indenture dated April 22, 2005 with CIBC Mellon Trust Company appointed trustee.

Penn West is an open-ended, unincorporated investment trust governed by the laws of the Province of Alberta. The purpose of Penn West is to indirectly explore for, develop and hold interests in petroleum and natural gas properties through investments in securities of subsidiaries and royalty interests in oil and natural gas properties. Penn West owns 100 percent of the common shares, directly or indirectly, of the entities that carry on the oil and natural gas business of Penn West. The activities of these entities are financed through interest-bearing notes from Penn West and third-party debt as described in note 6 to the audited consolidated financial statements.

Pursuant to the terms of net profit interest agreements (the "NPIs"), Penn West is entitled to payments from certain subsidiary entities equal to essentially all of the proceeds of the sale of oil and natural gas production less certain specified deductions. Under the terms of the NPIs, the deductions are in part discretionary, include the requirement to fund capital expenditures and asset acquisitions, and are subject to certain adjustments for asset dispositions.

Under the terms of its trust indenture, Penn West is required to make distributions to unitholders in amounts at least equal to its taxable income consisting of interest on notes, the NPIs, and any inter-corporate distributions and dividends received, less certain expenses.

2. Summary of significant accounting policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

a) Principles of consolidation

The consolidated financial statements, prior to the plan of arrangement, included the Company and its subsidiaries. Upon completion of the trust conversion, the consolidated financial statements have been prepared on a continuity of interests basis with Penn West as the successor to the Company.

The 2005 consolidated financial statements reflect the results of operations and cash flows of the Company and its subsidiaries for the period from January 1, 2005 to May 31, 2005 and the results of operations of Penn West and its subsidiaries and partnerships for the period from June 1, 2005 to December 31, 2005. As a result of the conversion into a trust, certain information included in the consolidated financial statements for prior periods may not be comparable. The consolidated financial statements include the accounts of Penn West and all its wholly owned subsidiaries and partnerships.

b) Other current assets

Other current assets include deposits, prepayments and inventory. Inventories are valued at the lower of cost and net realizable value.

c) Property, plant and equipment

i) Capitalized costs

The full cost method of accounting for oil and natural gas operations is followed, whereby all costs of acquiring, exploring and developing oil and natural gas reserves are capitalized. These costs include lease acquisition, geological and geophysical, exploration and development and related equipment costs. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction of capitalized costs, with no gain or loss recognized unless such disposition results in a significant change in the depletion and depreciation rate.

ii) Depletion and depreciation

Depletion and depreciation of resource properties is calculated using the unit-of-production method based on production volumes before royalties in relation to total proved reserves as estimated by independent petroleum engineers. Natural gas volumes are converted to equivalent oil volumes based upon the relative energy content of six thousand cubic feet of natural gas to one barrel of oil. In determining its depletion base, the Trust includes estimated future costs to be incurred in developing proved reserves and excludes estimated facility and equipment salvage values and the lower of cost and market of unevaluated properties. Significant natural gas processing facilities, net of estimated salvage values, are depreciated using the declining balance method over the estimated useful lives of the facilities.

iii) Ceiling test

The recoverability of accumulated costs in a cost centre is assessed based on undiscounted future cash flows from proved reserves, using forecast prices, and the cost of unproved properties. If accumulated costs are assessed to be not fully recoverable, the cost centre is written down to its fair value estimated as the present value of expected future cash flows, using forecast prices, from proved and probable reserves and the value of unproved properties. Expected future cash flows are discounted at the Trust's estimated risk free rate.

iv) Asset retirement obligations

The fair value of legal obligations for property abandonment and site restoration is recognized as a liability on the balance sheet as incurred with a corresponding increase to the carrying amount of the related asset. The recorded liability increases over time to its future amount through accretion charges included in depletion, depreciation and accretion. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the recorded liability. Asset retirement expenditures, up to the recorded liability at the time, are charged to the liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

The estimates in ii) and iii) and iv) are based on volumes and reserves calculated based on forecast sales prices, costs and regulations expected at the end of the fiscal year.

d) Joint operations

Some of the Trust's exploration and development activities are conducted jointly with others. The accounts reflect only the Trust's proportionate interest in such activities.

e) Financial instruments

The Trust has policies and procedures in place with respect to the required documentation and approvals for the use of derivative financial instruments and their use is limited to mitigating market price risk associated with expected cash flows.

The Trust elected to discontinue hedge accounting in 2005. Effective July 1, 2005 all financial instruments are accounted for using the fair value method. The fair value of these financial instruments is recognized on the balance sheet at inception and changes in the fair value of these instruments are recognized in income.

Prior to July 1, 2005, financial instruments that were determined to be hedges were accounted for as a component of the hedged item such as oil prices, natural gas prices, electricity costs or interest. The changes in market values of financial instruments accounted for as hedges were not recognized in the financial statements until the underlying oil or natural gas production, power purchases or interest cost was realized. Changes in market value of financial instruments determined not to be hedges, not qualifying as a hedge, or no longer effective as a hedge were fully recognized in the financial statements.

f) Enhanced oil recovery

The value of proprietary injectants is not recognized as revenue until reproduced and sold to third parties. The cost of injectants purchased from third parties for miscible flood projects is included in property, plant and equipment. These injectant costs are amortized as depletion and depreciation over the period of expected future economic benefit on a straight-line basis. Costs associated with the production of proprietary injectants are expensed.

g) Foreign currency translation

Monetary items, such as receivables and borrowings, are translated to Canadian dollars at the rate of exchange in effect at the balance sheet date. Non-monetary items, such as property, plant and equipment, are translated to Canadian dollars at the rate of exchange in effect when the transaction occurred. Revenues and expenses denominated in foreign currencies are translated at the average exchange rate in effect during the period. Foreign exchange gains or losses on translation are included in income.

h) Equity-based compensation

The Trust has a trust unit rights incentive plan that was implemented during the second quarter of 2005. Compensation expense for the plan is based on the fair value of rights issued, amortized over the remaining vesting periods on a straight-line basis. A Binomial Lattice option-pricing model is used to determine the fair value of rights granted.

Costs in respect of the employee trust unit savings plan are expensed as incurred.

The Company had a stock option plan in effect until May 31, 2005. As this stock option plan included a cash settlement alternative, stock-based compensation cost was measured for stock options outstanding at intrinsic value and recognized as an expense over the vesting period. Provision was made for all vested options at the period-end plus the portion of future option vestings attributable to the current period. Changes in intrinsic value of outstanding options between the grant date and the measurement date were reflected as stock-based compensation expense. Cash payments made on option exercises were charged against the stock-based compensation liability to the extent that prior provision was made for the payment. Payments in excess of the recorded liability were charged to stock-based compensation cost.

Compensation costs in excess of the recorded liability that were realized due to the cancellation of outstanding stock options as a result of the trust conversion were charged to income.

i) Revenue recognition

Revenues from the sale of crude oil, natural gas liquids and natural gas are recognized when title passes from the Company to the purchaser. Sales below or in excess of the Company's working interest share of production are recorded as inventory or deferred revenue respectively.

j) Income taxes

The corporate subsidiaries of Penn West use the asset and liability method of accounting for future income taxes. Temporary differences are calculated assuming that the financial assets and liabilities will be settled at their carrying amount. Future income taxes are computed on temporary differences using income tax rates that are expected to apply when future income tax assets and liabilities are realized or settled.

Penn West is taxable on income in excess of distributions to unitholders. No provision for future income taxes has been made for temporary differences in the trust, as it is required to distribute all of its taxable income to unitholders.

k) Goodwill

Goodwill is 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. Goodwill is not amortized and the balance is assessed for impairment on an annual basis or more frequently if circumstances arise that indicates impairment may have occurred.

The impairment test consists of two steps. First, the fair value of the Trust is compared to the carrying amount, including goodwill, to identify a potential impairment. If the fair value is greater than the carrying amount, goodwill is considered not to be impaired and the second step is not necessary. When the carrying amount exceeds the fair value, the second step requires the implied fair value of the goodwill to be compared to its carrying amount. The implied fair value of goodwill is computed by assigning fair values to the identifiable assets and

liabilities of the Trust as if it had been acquired in a business combination. If the carrying amount of goodwill exceeds its implied fair value, an impairment loss equal to the excess is recognized in the period.

l) Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of any contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the period. Actual results may differ materially from those estimates.

Significant estimates are included in the determination of the provisions for depletion and depreciation of petroleum and natural gas assets and the asset retirement obligations liability and the accretion thereof. Depletion and the ceiling test is based on estimates of reserves, which by their nature include estimates of future production rates, oil and gas prices and costs, as well as other assumptions. These and other estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material.

3. Merger with Petrofund Energy Trust ("Petrofund")

Penn West and Petrofund merged effective June 30, 2006 pursuant to a plan of arrangement (the "Arrangement"). Under the terms of the Arrangement, Petrofund unitholders received 0.6 of a Penn West unit for each Petrofund unit exchanged and a special distribution of $1.00 per unit plus $0.10 per unit to align the distribution dates of the trusts. Penn West accounted for the merger as an acquisition of Petrofund by Penn West using the purchase method of accounting. The consolidated financial statements of Penn West include the results of operations and cash flows of Petrofund from July 1, 2006 forward. The allocation of the consideration paid to the fair value of the identifiable assets and liabilities follows:

Purchase Price	
70.7 million Penn West trust units issued (1)	$ 3,032.4
Transaction costs	25.0
	$ 3,057.4

(1) Units issued at $42.91 per unit based on volume-weighted average for the five-day period, including two days before and two days after the announcement of the transaction.

Allocation of the Purchase Price	
Property, plant and equipment	$ 3,323.3
Working capital (deficiency)	(10.0)
Bank loan	(610.4)
Future income taxes	(199.5)
Asset retirement obligations	(98.0)
Goodwill	652.0
	$ 3,057.4

4. Property, plant and equipment

	As at December 31	
	2006	**2005**
Oil and natural gas properties, including production and processing equipment	**$ 9,666.0**	$ 5,710.4
Other	**17.2**	14.0
	9,683.2	5,724.4
Accumulated depletion and depreciation	**(2,549.1)**	(1,925.4)
Accumulated gas plant depreciation	**(95.1)**	(83.8)
	(2,644.2)	(2,009.2)
Net book value	**$ 7,039.0**	$ 3,715.2

Other than Penn West's net share of capital overhead recoveries, no general and administrative expenses are capitalized. In 2006, additions to property, plant and equipment included a $55.9 million increase related to additions to asset retirement obligations and changes in estimates, and a $1.7 million addition for future income taxes recorded on minor acquisitions. The lower of cost and market of unevaluated property excluded from the depletion base as at December 31, 2006 was $303 million (December 31, 2005 – $259 million). The depletion and depreciation calculation includes future capital costs to develop proved reserves of $718 million (2005 – $413 million).

An impairment test was performed on the oil and natural gas property interests at December 31, 2006, which determined that the estimated undiscounted future net cash flows associated with proved reserves, based on forecast prices and escalated costs, exceeded the carrying amount of the oil and natural gas property interests. Average prices of $8.59 per mcf (2005 – $8.46 per mcf) for natural gas and $66.04 per barrel (2005 – $54.95 per barrel) for liquids were used to calculate the future net revenues.

5. Goodwill

In 2006, Penn West recorded $652 million in goodwill in conjunction with the Petrofund merger. At December 31, 2006 an impairment test was performed and it was determined that there was no impairment to the goodwill balance.

6. Bank loan

	As at December 31 2006	2005
Bankers' acceptances and prime rate loans	**$ 1,285.0**	$ 542.0

As at December 31, 2006, the Company had an unsecured, extendible, three-year revolving syndicated credit facility with an aggregate borrowing limit of $1.8 billion plus a $100 million swing line facility, both of which expire on August 25, 2009. The credit facility contains provisions for stamping fees on bankers' acceptances and LIBOR loans and standby fees on unutilized credit lines that vary depending on certain consolidated financial ratios.

Letters of credit totaling $0.4 million (December 31, 2005 – $9 million) were outstanding on December 31, 2006 that reduced the amount otherwise available to be drawn on the swing line facility.

7. Asset retirement obligations

Total asset retirement obligations are based upon the present value of Penn West's net share of estimated future costs to abandon and reclaim all wells and facilities. The estimates were made by management and external consultants assuming current technology and enacted legislation.

The total uninflated and undiscounted amount to settle Penn West's asset retirement obligations at December 31, 2006 was $1.3 billion (December 31, 2005 – $0.8 billion). The asset retirement obligation was determined by applying an inflation factor of 2.0 percent (2005 – 1.7 percent) and the inflated amount was discounted using a credit-adjusted rate of 7.0 percent (2005 – 7.5 percent) over the expected useful life of the underlying assets, currently extending up to 50 years into the future with an average life of 23 years. Future cash flows from operating activities are expected to fund the obligations.

Changes to asset retirement obligations were as follows:

	2006	2005
Balance, beginning of period	**$ 192.4**	$ 180.7
Liabilities incurred during the period	**30.2**	9.8
Petrofund liabilities assumed on acquisition	**98.0**	—
Increase in liability due to change in estimates	**25.7**	3.4
Liabilities settled during the period	**(26.9)**	(22.6)
Accretion charges	**19.7**	21.1
Balance, end of period	**$ 339.1**	$ 192.4

8. Income taxes

On October 31, 2006, the Government of Canada announced a proposed new distribution tax on publicly traded income trusts. Under the proposed rules, effective for the 2011 tax year, distributions representing return on capital would no longer be deductible for income tax purposes by certain publicly traded trusts including Penn West. Any resultant taxable income in Penn West would be taxed at an estimated corporate tax rate. To date, the tax proposals have not been enacted and the impact on Penn West's organizational structure, current and future income taxes is not currently determinable.

As at December 31, future income tax assets (liabilities) arose from temporary differences as follows:

	2006	2005
Property, plant and equipment	**$ (883.1)**	$ (753.7)
Commodity contracts	**(17.6)**	—
Asset retirement obligations	**101.4**	67.0
Other	**6.7**	4.6
	$ (792.6)	$ (682.1)
Future income tax liability	**$ (792.6)**	$ (682.1)

The trust currently maintains an income tax status that permits it to deduct distributions to unitholders in addition to other items. As a result, no future income tax provision or recovery was made for temporary differences in the trust. As at December 31, 2006, the book amount of the trust's assets and liabilities exceed their tax basis by $1.7 billion. If the tax proposals are enacted, the recording of future income taxes to reflect the temporary timing differences in the trust could be required.

The provision for (recovery of) income taxes reflects an effective tax rate that differs from the combined federal and provincial statutory tax rate as follows:

	Year ended December 31 2006	2005

Income before taxes	**$ 574.1**	$ 644.9
Corporate income tax rate	**35.2%**	38.4%
Computed income tax provision	**$ 202.1**	$ 247.6
Increase (decrease) resulting from:		
Net income attributable to the trust	**(197.4)**	(154.3)
Non-deductible Crown payments, net	**36.1**	71.0
Resource allowance	**(38.4)**	(75.9)
Tax rate reductions	**(108.6)**	(31.1)
Non-taxable foreign exchange	**—**	0.8
Other	**—**	(5.1)
Total income taxes	**$ (106.2)**	$ 53.0
Current	**—**	54.1
Future recovery	**(106.2)**	(1.1)
	$ (106.2)	$ 53.0

9. Unitholders' equity

a) Authorized

i) An unlimited number of Voting Trust Units, which are redeemable at the option of the unitholder.

ii) An unlimited number of Special Voting Units, which enable the Trust to provide voting rights to holders of any exchangeable shares that may be issued by any direct or indirect subsidiaries of the Trust. Except for the right to vote, the Special Voting Units do not confer any rights.

Trust units are redeemable at any time at the option of the unitholder. The redemption price is equal to the least of 95 percent of the closing market price on the date the units were tendered for redemption, 95 percent of the volume-weighted average market price for the 10 days immediately after the date the units were tendered for redemption, or 95 percent of the closing market price on the date of redemption. Total redemptions are limited to $250,000 in any calendar month, subject to waiver at the discretion of the administrator. If the limitation is not waived, the amount payable in excess of the $250,000 will be settled by the distribution of redemption notes to the redeeming unitholders by the Trust.

Penn West has a Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP") that provides eligible unitholders the opportunity to reinvest monthly cash distributions into additional units at a potential discount. Units are issued from treasury at 95 percent of the 10-day volume-weighted average market price when available. When units are not available from treasury they are acquired in the open market at prevailing market prices.

Unitholders who participate in the DRIP may also purchase additional units, subject to a monthly maximum of $5,000 and a minimum of $500. Optional cash purchase units are acquired, without a discount, in the open market at prevailing market prices or issued from treasury at the 10-day volume-weighted average market price.

b) Issued

Penn West shareholders received three trust units for each common share held resulting in the issuance of 163,137,018 trust units in exchange for the common shares of Penn West pursuant to the plan of arrangement.

No special voting units were issued or outstanding.

Common shares of Penn West	Shares	Amount
Balance, December 31, 2003	53,692,290	$ 505.6
Issued on exercise of stock options	176,455	5.2
Liability settlement on stock options exercised for shares	—	4.5
Balance, December 31, 2004	53,868,745	$ 515.3
Issued on exercise of stock options	488,399	17.0
Issued to employee stock savings plan	21,905	1.8
Cancellation of certificates	(43)	—
Liability settlements on stock options exercised for shares	—	22.0
Balance, May 31, 2005 prior to plan of arrangement	54,379,006	$ 556.1
Exchanged for Trust units	(54,379,006)	(556.1)
Balance as at May 31, 2005	—	$ —

Voting Trust Units	Units	Amount
Issued to settlor for cash, April 22, 2005	1,250	$ —
Exchanged for Penn West shares, May 31, 2005	163,137,018	556.1
Issued to employee trust unit savings plan	151,745	4.9
Balance, December 31, 2005	163,290,013	561.0
Issued on exercise of trust unit rights	407,750	10.6
Issued to employee trust unit savings plan	295,449	12.3

Issued to DRIP	2,459,870	96.1
Issued on Petrofund merger	70,673,137	3,032.4
Balance, December 31, 2006	237,126,219	$ 3,712.4

Special Voting Units

No Special Voting Units were issued.

c) Contributed Surplus

	2006	2005
Balance, beginning of period	**$ 5.5**	$ —
Equity-based compensation expense	**11.3**	5.5
Net benefit on rights exercised(1)	**(0.4)**	—
Balance, end of period	**$ 16.4**	$ 5.5

(1) Upon exercise of trust unit rights, the net benefit is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

10. Equity-based compensation

a) Stock option plan

Until May 31, 2005, the Company had a stock option plan for the benefit of its employees and directors. Stock options vested over a five-year period and, if unexercised, expired six years from the date of grant. The stock option plan included a cash payment alternative and stock-based compensation costs were recorded based on changes to the share price at the end of each quarter and any changes to the number of outstanding options. Pursuant to the plan of arrangement, all stock options outstanding on the date of conversion were settled for cash of $84.77 per share or by issuing shares. The continuity of the compensation liability and the outstanding options to the date of cancellation were as follows:

	2005
Balance, beginning of period	$ 91.9
Compensation expense provision	71.7
Cash payments on exercise of stock options	(141.6)
Liability settlements on stock options exercised for shares	(22.0)
Balance, end of period	$ —

Penn West Petroleum Ltd. Stock Options	Number of Stock Options	Weighted Average Exercise Price
Outstanding, January 1, 2005	3,728,980	$ 39.00
Granted	82,600	79.51
Exercised for common shares	(488,399)	34.72
Settled for cash	(3,212,931)	40.51
Forfeited	(110,250)	44.26
Outstanding, May 31, 2005	—	$ —

b) Trust unit rights incentive plan

On the close of the trust conversion in May 2005, Penn West implemented a unit rights incentive plan that allows Penn West to issue rights to acquire trust units to directors, officers, employees and other service providers. Under the terms of the plan, the number of trust units reserved for issuance shall not exceed 10 percent of the aggregate number of issued and outstanding trust units of Penn West. Unit right exercise prices are administrated to be equal to the volume-weighted average trading price of the trust units on the Toronto Stock Exchange for the five trading days immediately prior to the date upon which the unit rights are granted. If certain conditions are met, the exercise price per unit may be reduced by deducting from the grant price the aggregate of all monthly distributions, on a per unit basis, paid by Penn West after the grant date. In 2006, a Binomial Lattice model was adopted to compute the fair value of rights granted. Penn West used the Black-Scholes option pricing model to compute the fair value of rights granted in 2005. This transition had no material effect on the fair value of the rights granted. Rights granted under the plan prior to November 13, 2006 vest over a five-year period and expire six years after the date of the grant. Rights granted subsequent to this date vest over a three-year period and expire four years after the date of the grant.

	2006		2005	
Trust Unit Rights	Number of Unit Rights	Weighted Average Exercise Price	Number of Unit Rights	Weighted Average Exercise Price

Outstanding, beginning of period	**9,447,625**	**$ 28.45**	—	$ —
Granted	**3,257,622**	**39.77**	10,045,325	29.73
Exercised	**(407,750)**	**24.65**	—	—
Forfeited	**(1,012,625)**	**33.38**	(597,700)	28.46
Balance before reduction of exercise price	**11,284,872**	**30.89**	9,447,625	29.81
Reduction of exercise price for distributions paid	**—**	**(3.13)**	—	(1.36)
Outstanding, end of period	**11,284,872**	**$ 27.76**	9,447,625	$ 28.45
Exercisable, end of period	**1,125,300**	**$ 23.16**	—	$ —

	Options Outstanding			Options Exercisable	
Range of Grant Prices	Number Outstanding	Weighted Average Exercise Price(1)	Weighted Remaining Contractual Life (years)	Number Exercisable	Weighted Average Exercise Price(1)
$28.00 — $32.99	6,570,300	$ 22.85	4.4	1,073,700	$ 22.87
$33.00 — $37.99	2,569,572	31.13	4.7	51,600	29.06
$38.00 — $42.99	2,027,500	38.50	5.4	—	—
$43.00 — $47.99	117,500	42.96	5.7	—	—
	11,284,872	**$ 27.76**	**4.7**	**1,125,300**	**$ 23.16**

(1) Exercise prices are adjusted for distributions if certain conditions are met as described above.

Penn West recorded compensation expense of $11.3 million for the year ended December 31, 2006 (2005 – $5.5 million). Compensation expense subsequent to the trust conversion is based on the fair value of rights issued and is amortized over the remaining vesting periods on a straight-line basis.

During the year, Penn West adopted the recommendations in Emerging Issues Committee Abstract 162, *"Stock-based compensation for employees eligible to retire before the vesting date"*. The recommendation requires early recognition of compensation expense for employees eligible to retire or for employees who will become eligible to retire during the vesting period. The adoption of these recommendations did not affect reported compensation expense.

The Binomial Lattice option-pricing model was used to determine the fair value of trust unit rights granted with the following weighted average assumptions:

	Year ended December 31, 2006 (1)	
	Five-year Vesting Period	Three-year Vesting Period
Average fair value of trust unit rights granted (per unit)	$ 8.05	$ 7.18
Expected life of trust unit rights (years)	4.5	3.0
Expected volatility (average)	23.8%	25.5%
Risk-free rate of return (average)	4.1%	3.9%
Distribution yield	9.9%	11.5%

(1) Rights granted prior to November 13, 2006 vest over a five-year period. Rights granted subsequent to November 13, 2006 vest over a three-year period.

In 2005, the Black-Scholes option pricing model was used to determine the fair value of the Trust unit rights granted with the following weighted average assumptions:

	Seven months ended December 31 2005
Average fair value of trust unit rights granted (per unit)	
Directors and officers	$ 6.50
Other employees	$ 6.13
Expected life of trust unit rights (years)	
Directors and officers	5.0
Other employees	4.5
Expected volatility (average)	16%
Risk-free rate of return (average)	3.4%
Expected distribution rate	Nil

c) Employee trust unit savings plan

Penn West has an employee trust unit savings plan for the benefit of all employees. Under this savings plan, employees may elect to contribute up to 10 percent of their salary. Penn West matches employee contributions at a rate of $1.50 for each $1.00. Both the employee's and Penn West's contribution are used to acquire Penn West trust units. These trust units may be issued from treasury at the five-day volume weighted-average month-end trading price on the Toronto Stock Exchange or purchased in the open market. During 2006, 295,449 treasury units were contributed to the plan at an average price of $41.71 per unit and a total cost of $12.3 million. No trust units have been purchased in the open market since the trust conversion.

Prior to the trust conversion, the Company had a stock savings plan with essentially the same terms as the trust unit savings plan. During 2005, 20,355 employer contribution shares (equivalent to 61,065 trust units) were purchased in the open market at an average price of $81.48 per share ($27.16 per equivalent trust unit) and a total cost of $1.7 million and 21,905 shares (equivalent to 65,715 trust units) were issued from treasury.

11. Distributions payable to unitholders

Under the terms of its trust indenture, Penn West is required to make distributions to unitholders in amounts at least equal to its taxable income consisting of interest on notes, the NPIs, and any inter-corporate distributions and dividends received, less certain expenses. Distributions may be monthly or special and in cash or in trust units at the discretion of the board of directors. Distributions payable to unitholders is the amount declared and payable by the Trust.

Accumulated Cash Distributions	2006	2005
Balance, beginning of period	**$ 321.5**	$ —
Distributions declared	**811.8**	321.5
Balance, end of period	**$ 1,133.3**	$ 321.5
Distributions per unit(1)	**$ 4.05**	$ 1.97
Accumulated cash distributions per unit, beginning of period	**1.97**	—
Accumulated cash distribution per unit, end of period	**$ 6.02**	$ 1.97

(1) Distributions per unit are the sum of the per unit amounts declared monthly to unitholders.

12. Financial instruments

Financial instruments included in the balance sheets consist of accounts and taxes receivable, fair values of 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 the accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. Penn West, from time to time, uses various types of financial instruments to reduce its exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these instruments exposes Penn West to credit risks associated with the possible non-performance of counterparties to derivative instruments. Penn West limits this risk by transacting only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

Penn West's revenue from the sale of crude oil, natural gas liquids and natural gas is 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.

Variations in interest rates directly impact interest costs. From time to time, Penn West may increase the certainty of future interest rates using financial instruments to swap floating interest rates for fixed rates.

Crude oil sales are referenced to or denominated in US dollars. Crude oil prices realized in Canadian dollars are accordingly impacted directly by Canadian to US exchange rates. From time to time, Penn West may use financial instruments to fix future exchange rates.

As at December 31, 2006, Penn West had the following financial instruments outstanding:

	Notional Volume	Remaining Term	Pricing	Market Value
Crude Oil				
WTI Costless Collars	3,000 bbls/day	Jan/07 – Mar/07	US$56.67 to $84.28/bbl	$ 0.2
WTI Costless Collars	1,000 bbls/day	Jan/07 – Jun/07	US$60.00 to $73.10/bbl	0.2
WTI Costless Collars	1,000 bbls/day	Apr/07 – Jun/07	US$60.00 to $80.00/bbl	0.2
WTI Costless Collars	25,000 bbls/day	Jan/07 – Dec/07	US$56.00 to $83.80/bbl	7.9

WTI Costless Collars	10,000 bbls/day	Jan/08 – Jun/08	US$60.00 to $94.55/bbl	6.2
Natural Gas				
AECO Costless Collars	9,200 mcf/day	Jan/07 – Mar/07	$9.18 to $12.97/mcf	1.0
AECO Costless Collars	73,400 mcf/day	Jan/07 – Oct/07	$7.63 to $9.68/mcf	20.8
Electricity				
Alberta Power Pool Swaps	67 MW	2007	$49.55/MWh	17.3
Alberta Power Pool Swaps	2 MW	2008	$57.00/MWh	0.4
Interest Rate Swaps	$100.0	Jan/07 – Mar/08	4.356%	(0.2)
Total				$ 54.0

Effective July 1, 2005, Penn West elected to discontinue the designation of financial instruments as hedges, choosing to account for these instruments using the fair value method. In accordance with the transitional accounting recommendations, the fair value of power contracts at July 1, 2005 in the amount of $16.7 million was recorded as a deferred gain and was taken into income over the remaining life of the contracts. Changes in the fair value of all outstanding financial commodity, power and interest rate contracts are reflected on the balance sheet with a corresponding unrealized gain or loss in income.

The following table reconciles the changes in the fair value of financial instruments no longer designated as hedges:

Risk Management	**2006**	**2005**
Balance, beginning of period	**$ 8.5**	$ —
Deferred gain	**—**	16.7
Unrealized gain on financial instruments:		
Commodities	**51.3**	(14.8)
Electricity contracts	**(5.6)**	6.6
Interest rate swaps	**(0.2)**	—
Balance, end of period	**$ 54.0**	$ 8.5

Deferred gain on financial instruments	**2006**	**2005**
Balance, beginning of period	**$ (11.9)**	$ —
Deferred gain	**—**	(16.7)
Amortization	**11.9**	4.8
Balance, end of period	**$ —**	$ (11.9)

13. Per unit amounts

Penn West follows the treasury stock method to compute the dilutive impact of unit rights. The treasury stock method assumes that the proceeds received from the pro-forma exercise of in-the-money trust unit rights are used to purchase trust units at average market prices.

The number of incremental shares included in diluted earnings per share ("EPS") is computed using the average volume-weighted market price of common shares for each interim period. In addition, contracts that could be settled in cash or common shares are assumed settled in common shares if share settlement is more dilutive. Shares to be issued upon conversion of convertible instruments with a mandatory conversion feature would be included in the basic weighted average EPS calculation from the date when conversion becomes mandatory.

The weighted average number of trust units used to calculate per unit amounts was:

	Year ended December 31	
	2006	**2005**
Basic	**200,758,870**	162,632,127
Diluted	**203,509,494**	165,878,364

In 2006, 1.7 million rights (2005 – nil) were excluded in calculating the weighted average number of diluted trust units as they were considered anti-dilutive.

14. Contractual obligations and commitments

The following is a summary the contractual obligations due in the next five years and thereafter:

	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 CO_2 purchases and $25.2 million for processing fees related to interests in the Weyburn Unit.

Our credit facility expires in three years, which if not renewed would require the repayment of all amounts outstanding. We believe the facility

will be renewed prior to that time.

15. Change in non-cash working capital

Changes in non-cash working capital items increased (decreased) cash and cash equivalents as follows:

	Year ended December 31	
	2006	**2005**
Accounts receivable	**$ (54.3)**	$ (53.9)
Other current assets	**(27.0)**	(9.2)
Accounts payable and accrued liabilities	**78.8**	(2.5)
Taxes payable	**(10.6)**	0.6
Petrofund	**(18.8)**	—
	$ (31.9)	$ (65.0)
Operating activities	**$ (43.6)**	$ (1.8)
Investing activities	**11.7**	(63.2)
Financing activities	**—**	—
	$ (31.9)	$ (65.0)

16. Plan of arrangement costs

Effective May 31, 2005, the Penn West commenced operations as an oil and gas income trust pursuant to a plan of arrangement approved by the shareholders on May 27, 2005. Certain amounts, related to the plan of arrangement, were charged to accumulated earnings:

Rate differences on income taxes paid	$ 13.3
Incremental capital taxes	13.4
Financial advisor fees	5.6
Filing fees, communication, professional fees and other	4.0
Tax benefit on fees	(3.4)
	$ 32.9

In addition, the trust conversion resulted in a short income tax year that accelerated $146.3 million of cash income taxes as a significant amount of Penn West's taxable income was earned in a partnership.

17. Related-party transactions

During 2006, Penn West paid $4.1 million (2005 – $ 2.1 million) of legal fees to a law firm of which a partner is also a director of Penn West.

18. Subsequent event

On February 9, 2007, Penn West announced it had recently 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.

INVESTOR INFORMATION

Officers

William Andrew
President and CEO

David Middleton
Executive Vice President and COO

Thane Jensen
Senior Vice President, Exploration and Development

William Tang Kong
Senior Vice President, Corporate Development

Todd Takeyasu

Senior Vice President and CFO

Gregg Gegunde
Vice President, Development

Eric Obreiter
Vice President, Production

Kristian Tange
Vice President, Business Development

Anne Thomson
Vice President, Exploration

Lucas Law
Vice President, Asset Management

Keith Luft
Vice President, Land and Legal

Directors

John A. Brussa
Chairman
Calgary, Alberta

William E. Andrew
Calgary, Alberta

Thomas E. Phillips (1)(2)(3)(4)(5)
Calgary, Alberta

James C. Smith (1)(3)(4)(5)
Calgary, Alberta

Murray R. Nunns (1)(2)(3)(5)
Calgary, Alberta

George H. Brookman (1)(4)(5)
Calgary, Alberta

James E. Allard (1)
Calgary, Alberta

Jeffery E. Errico (3)(5)
Calgary, Alberta

Frank Potter (2)(4)
Toronto, Ontario

Notes:

(1) Member of the Audit Committee

(2) Member of the Human Resources and Compensation Committee

(3) Member of the Reserves Committee

(4) Member of the Governance Committee

(5) Member of the Health, Safety and Environment Committee

Legal Counsel

Burnet, Duckworth & Palmer
Calgary, Alberta

Thackray Burgess
Calgary, Alberta

Dorsey & Whitney LLP
Vancouver, B.C.

Bankers

Canadian Imperial Bank of Commerce
Royal Bank of Canada
The Bank of Nova Scotia
Bank of Montreal
Bank of Tokyo-Mitsubishi (Canada)
Alberta Treasury Branches
Sumitomo Mitsui Banking Corporation of Canada
BNP Paribas (Canada)
Societe Generale
HSBC Bank Canada
Toronto Dominion Bank
Citibank, N.A.
National Bank of Canada
Fortis Capital (Canada) Ltd.
Union Bank of California, N.A.

Transfer Agent

CIBC Mellon Trust Company
Calgary, Alberta

Investors are encouraged to contact The CIBC Mellon Trust Company for information regarding their security holdings. They can be reached at:

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(416) 643-5000 or toll-free throughout
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Independent Reserve Evaluator

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Stock Exchange Listing

Toronto Stock Exchange
Trading Symbol: PWT.UN

New York Stock Exchange
Trading Symbol: PWE

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Notes to Reader

This document contains forward-looking statements (forecasts) under applicable securities laws. Forward-looking statements are necessarily based upon assumptions and judgements with respect to the future including, but not limited to, the outlook for commodity markets and capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. Many of these factors can be difficult to

predict. As a result, the forward-looking statements are subject to known or unknown risks and uncertainties that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

Refer to our MD&A for a more detailed discussion of forward-looking statements.

Abbreviations

bbl	barrel (oil or natural gas liquids)
mmbbl	million barrels
bbls per day or bbls/day or bbls/d	barrels per day
boe	barrels of oil equivalent (based on 6 mcf of natural gas equals one barrel of oil)
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet (natural gas)
mmcf	million cubic feet
mmcf per day	million cubic feet per day
NGL	natural gas liquids
GJ	gigajoule
bcf	billion cubic feet
API	American Petroleum Institute
TSX	Toronto Stock Exchange
NYSE	New York Stock Exchange
WTI	West Texas Intermediate
MW	megawatt
MWh	megawatt-hour

Conversions of Units

Imperial	Metric
1 ton	0.907 tonnes
1.102 tons	1 tonne
1 acre	0.40 hectares
2.5 acres	1 hectare
1 bbl	0.159 cubic metres
6.29 bbls	1 cubic metre
1 mcf	28.2 cubic metres
.035 mcf	1 cubic metre
1 mile	1.61 kilometres
0.62 miles	1 kilometre

Unless otherwise stated, all financial sums are stated in Canadian dollars.

PENN WEST
ENERGY TRUST

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Exhibit 99.4

AUDITORS' REPORT ON RECONCILIATION TO UNITED STATES GAAP

TO THE BOARD OF DIRECTORS OF PENN WEST ENERGY TRUST

On February 28, 2007, we reported on the consolidated balance sheets of Penn West Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of income and retained earnings and cash flows for the years then ended, which are included in the annual report on Form 40-F. In connection with our audits, conducted in accordance with Canadian generally accepted auditing standards, of the aforementioned consolidated financial statements, we also have audited the related supplemental note entitled "Reconciliation of Canadian and United States Generally Accepted Accounting Principles" included in the Form 40-F. This supplemental note is the responsibility of the Trust's management. Our responsibility is to express an opinion on this supplemental note based on our audits.

In our opinion, such supplemental note, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

Chartered Accountants

Calgary, Canada
February 28, 2007 (except for note (a),
which is dated March 26, 2007)

Reconciliation of Canadian and United States Generally Accepted Accounting Principles

Canadian Generally Accepted Accounting Principles ("GAAP") varies in certain respects from U.S. GAAP. As required by the United States Securities and Exchange Commission, the effect of these differences in principles on Penn West Energy Trust's (the "Trust") consolidated financial statements is described and quantified below:

The application of U.S. GAAP would have the following effects on reported net income:

Years ended December 31	2006	2005
Net income as reported in the Consolidated Statements of Income - Canadian GAAP	$ 665.6	$ 577.2
Adjustments		
Unit-based compensation (note (g))	(9.6)	—
Risk management activities (note (b))	(11.9)	0.1
Plan of arrangement costs (note (c))	—	(36.3)
Income tax effect of the above adjustments	3.6	3.4
Net and Other Comprehensive Income, as adjusted before cumulative effect of change in accounting policy (note (d))	647.7	544.4
Cumulative effect of change in accounting policy, net of income taxes (note (g))	(9.2)	0.0
Net and Other Comprehensive Income - U.S. GAAP, as adjusted	$ 638.5	$ 544.4
Net income per trust unit before cumulative effect of change in accounting policy		
Basic	$ 3.23	$ 3.35
Diluted	3.20	3.28
Cumulative effect of change in accounting policy		
Basic	(0.05)	—
Diluted	(0.05)	—
Net Income per trust unit		
Basic	3.18	3.35
Diluted	$ 3.15	$ 3.28
Weighted average number of trust units outstanding (in millions)		
Basic	200.8	162.6
Diluted	202.6	165.9
Retained earnings (deficit) - U.S. GAAP		
Balance, beginning of the period - U.S. GAAP	$ (3,723.8)	$ 1,400.8
Net Income - U.S. GAAP	638.5	544.4
Change in redemption value of Trust units (note (e))	1,501.3	(5,336.7)
Dividends	—	(10.8)
Distributions declared	(811.8)	(321.5)
Balance, end of period - U.S. GAAP	$ (2,395.8)	$ (3,723.8)

The application of U.S. GAAP would have the following effects on the reported balance sheets:

Year ended December 31, 2006	Canadian GAAP	U.S. GAAP
ASSETS		
Current		
Accounts receivable	$ 268.7	$ 268.7
Risk Management (note (b))	54.0	54.0
Other	56.0	56.0
	378.7	378.7
Property, plant and equipment (note (a))	7,039.0	7,039.0
Goodwill	652.0	652.0
	$ 8,069.7	**$ 8,069.7**
LIABILITIES AND UNITHOLDERS' EQUITY (DEFICIENCY)		
Current		
Accounts payable	$ 382.9	$ 382.9
Taxes payable	1.2	1.2
Distributions payable	80.6	80.6
Deferred gain on financial instruments (note (b))	—	—
	464.7	464.7
Bank loan	1,285.0	1,285.0
Asset retirement obligations	339.1	339.1
Unit rights liability (note (g))	—	34.1
Future income taxes	792.6	793.7
	2,416.7	2,451.9
Total Liabilities	2,881.4	2,916.6
Unitholders' mezzanine equity (note (e))	—	7,548.9
Unitholders' Equity (Deficiency)		
Unitholders' capital (note (e))	3,712.4	—
Contributed Surplus (note (e))	16.4	—
Retained earnings (deficit) (note (e))	1,459.5	(2,395.8)
	5,188.3	(2,395.8)
	$ 8,069.7	**$ 8,069.7**

Year ended December 31, 2005	Canadian GAAP	U.S. GAAP
ASSETS		
Current		
Accounts receivable	$ 214.4	$ 214.4
Risk Management (note (b))	8.5	8.5
Other	29.0	29.0
	251.9	251.9
Property, plant and equipment (note (a))	3,715.2	3,715.2
	$ 3,967.1	**$ 3,967.1**
LIABILITIES AND UNITHOLDERS' EQUITY (DEFICIENCY)		
Current		
Accounts payable	$ 304.1	$ 304.1
Taxes payable	11.8	11.8
Distributions payable	50.6	50.6
Deferred gain on financial instruments (note (b))	11.9	0.0
	378.4	366.5
Bank loan	542.0	542.0
Asset retirement obligations	192.4	192.4
Future income taxes	682.1	686.8
	1,416.5	1,421.2
Total Liabilities	1,794.9	1,787.7
Unitholders' mezzanine equity (note (e))	—	5,903.2
Unitholders' Equity (Deficiency)		
Unitholders' capital (note (e))	561.0	—

Contributed Surplus (note (e))	5.5	—
Retained earnings (deficit) (note (e))	1,605.7	(3,723.8)
	2,172.2	(3,723.8)
	$ 3,967.1	**$ 3,967.1**

The application of U.S. GAAP would have the following effects on reported cash flows (note f):

Years ended	Canadian GAAP	U.S. GAAP
December 31, 2006		
Cash flows from operating activities	$ 1,106.3	$ 1,106.3
Cash flows from investing activities	(591.2)	(591.2)
Cash flows from financing activities	(515.1)	(515.1)
	$ —	**$ —**
December 31, 2005		
Cash flows from operating activities	$ 932.8	$ 750.2
Cash flows from investing activities	(519.9)	(519.9)
Cash flows from financing activities	(412.9)	(230.3)
	$ —	**$ —**

(a) Property, plant and equipment and depletion and depreciation

Under Canadian GAAP, an impairment exists when the net book value of the petroleum and natural gas properties exceeds the sum of the undiscounted future cash flows from proved reserves calculated using forecast prices and costs, and the cost of unproven properties. If an impairment is determined to exist, the impairment is measured as the amount by which the net book value of the petroleum and natural gas properties exceeds the sum of the present value of future discounted cash flows from proved plus probable reserves using forecast prices and costs, and the cost of unproved properties.

Under U.S. GAAP, the net book value of petroleum and natural gas properties, net of deferred income taxes, is limited to the present value of after-tax future net cash flows from proved reserves, discounted at 10 percent and using prices and costs at the balance sheet date, plus the lower of cost and fair value of unproved properties. The impairment test is performed annually on December 31 and, as elected by the Trust, recalculated seven business days prior to the filing date of the Trust's consolidated financial statements. If there is impairment indicated on December 31, which no longer exists at the time of the second test, no write down is required. At December 31, 2006, an impairment of $443.2 million was indicated but upon the re-performance of the test there was no indication of impairment as commodity prices increased from those applied at December 31, 2006. The application of the impairment test under U.S. GAAP did not result in a write-down of capitalized costs in either 2006 or 2005.

(b) Derivative financial instruments

Under Canadian GAAP, the disclosure of the fair value of derivative financial instruments, which qualify for hedge accounting, is required with no recorded effect on assets, liabilities or net income. Under U.S. GAAP, derivative financial instruments qualifying for hedge accounting must be measured and presented on the consolidated balance sheet at fair value as either an asset or liability with changes in the fair value of all cash flow hedges recognized in other comprehensive income until such time as the underlying physical transaction occurs. Any change in the fair value of derivative financial instruments, which no longer qualify for hedge accounting, is recognized in income of the period.

The hedging documentation requirements under Canadian GAAP differed in certain respects from those required under U.S. GAAP. As a result, certain derivative financial instruments accounted for as hedges under Canadian GAAP did not qualify for hedge accounting when the Trust first applied U.S. GAAP.

Effective July 1, 2005, the Trust elected to discontinue designating derivative instruments as accounting hedges. As a result of this change, a deferred gain on financial instruments of $16.7 million, that represented the fair value of these financial contracts on July 1, 2005, was recognized on the consolidated balance sheet for Canadian GAAP purposes. This deferred gain was amortized to income over the remaining life of the financial contracts. For U.S. GAAP purposes, as the outstanding instruments at the time U.S. GAAP was adopted did not qualify for hedge accounting, all of the Trust's financial contracts were measured at fair value, with corresponding changes in fair values recognized as unrealized gains or losses in income of the period. The amortization of the deferred gain on financial instruments for Canadian GAAP purposes of $11.9 million ($8.3 million net of tax) was recorded as a reduction to U.S. GAAP income as this amount was previously recorded under U.S. GAAP. In 2005, the change in fair value resulted in the recognition of a risk management activity gain of $0.1 million ($0.1 million net of tax) reflected in the statement of income.

(c) Plan of arrangement costs

Effective May 31, 2005, Penn West Petroleum Ltd. was reorganized into the Trust. Under Canadian GAAP, plan of arrangement costs totaling $36.3 million ($32.9 million net of tax) were charged directly to retained earnings in 2005. Under U.S. GAAP, these costs are treated as a charge to income in the period.

(d) Other comprehensive income

Comprehensive income is recognized and measured under U.S. GAAP pursuant to Statement of Financial Accounting Standard ("SFAS") No. 130, "Reporting Comprehensive Income". This standard defines comprehensive income as all changes in equity other than those resulting from investments by owners and distributions to owners. Comprehensive income is comprised of two components, net income and other comprehensive income ("OCI"). OCI refers to amounts that are recorded as an element of unitholders' equity but are excluded from net income because these transactions or events were attributed to changes from non-owner sources. Comprehensive income was equivalent to net income in 2006 and 2005.

(e) Unitholders' mezzanine equity

U.S. GAAP requires that trust units, which are redeemable at the option of the unitholder, be valued at their redemption amount and presented as temporary equity on the balance sheet. The redemption value of the Penn West trust units is determined based on 95% of the market value of the trust units at each balance sheet date. Under Canadian GAAP, all trust units are classified as unitholders' equity. As at December 31, 2006, the Trust reclassified $7,548.9 million (2005 - $5,893.1 million) as unitholders' mezzanine equity in accordance with U.S. GAAP.

Changes in unitholders' mezzanine equity in excess of trust units issued, net of redemptions, net income and cash distributions in a period are recognized as charges to the deficit. As a result, the Trust recorded a reduction of $1,501.3 million (2005 – charge of $5,332.1 million) to deficit as at December 31, 2006.

(f) Statements of cash flow

Under U.S. GAAP, plan of arrangement costs incurred in 2005 were treated as period costs. Accordingly, the associated cash outflows of $36.3 million are considered an operating activity pursuant to SFAS No. 95, "Statement of Cash Flows". In addition, for U.S. GAAP purposes, cash outflows related to the payment of income taxes are classified as operating activities. As such, the future income tax liability settled upon conversion to a trust on May 31, 2005 of $146.3 million is considered an operating activity under U.S. GAAP.

(g) Unit-based compensation

On January 1, 2006, the Trust adopted SFAS 123R, "Share-Based Payment" using the modified prospective method of application and adopted the fair value method of accounting for all grants under the rights plan. Under SFAS 123R, rights granted under the rights plan are considered liability awards whereas they were previously considered equity awards under SFAS 123. As a result of the adoption of SFAS 123R on January 1, 2006 the Trust recorded a trust unit rights liability of $14.7 million, which represented the fair value of all outstanding unit rights on that date, in proportion to the requisite service period rendered to that date. In addition, contributed surplus was reduced by $5.5 million representing previously recognized compensation cost for all outstanding unit rights for Canadian GAAP purposes, and an expense of $9.2 million was recorded as a cumulative effect of a change in accounting policy.

The trust unit rights liability is calculated based on the fair value of the grants, determined by the Binomial Lattice model at each reporting date until the date of settlement. Compensation cost is recorded based on the change in fair value of the rights during each reporting period. When rights are exercised, the proceeds plus the amount recorded as a trust unit rights liability are recorded to mezzanine equity.

A U.S. GAAP difference exists as rights granted under the rights plan are considered equity awards for Canadian GAAP purposes. Unit-based compensation is based upon the fair value of rights issued, determined only on the grant date. This initial fair value is charged to income over the vesting period of the rights with a corresponding increase in contributed surplus. When rights are exercised, consideration received plus the fair value recorded in contributed surplus is transferred to unitholders' equity. For the year ended December 31, 2006, compensation expense calculated under U.S. GAAP was $9.6 million higher than compensation expense calculated under Canadian GAAP.

In 2005, unit rights that were redeemable at the option of the holder met the criterion for classification as temporary equity under U.S. GAAP. The redemption amount of the unit rights was recorded as mezzanine equity based upon the number of vested awards on the balance sheet date. The change in redemption amount of the Trust unit rights was reclassified to mezzanine equity; firstly from contributed surplus, and secondly from retained earnings (deficit) once the contributed surplus balance was reduced to nil. For the year ended December 31, 2005, contributed surplus was reduced by $5.5 million to nil, retained earnings (deficit) was reduced by $4.6 million and mezzanine equity was increased by $10.1 million under U.S. GAAP.

(h) Net income available to unitholders

Net income available to unitholders under Emerging Issues Task Force D-98 "Classification and Measurement of Redeemable Securities" was:

	2006	2005
Net and Other Comprehensive Income – U.S. GAAP, as adjusted	$ 638.5	$ 544.4
Change in redemption value of Trust units	1,501.3	(5,336.7)
Net income (loss) available to unitholders	$ 2,139.8	$ (4,792.3)
Net income (loss) available to unitholders per unit		
Basic	$ 10.66	$ (29.47)
Diluted	$ 10.56	$ (29.47)

Changes in redemption value of Trust units are charged to retained earnings and are included in net income (loss) available to unitholders for purposes of calculating net income per unit.

Recent U.S. accounting pronouncements

In February 2006, the FASB issued SFAS No. 155, “Accounting for Certain Hybrid Financial Instruments” (“SFAS No. 155”). This statement amends SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities”, and SFAS No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities”. This Statement resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, “Application of Statement 133 to Beneficial Interests in Securitized Financial Assets”. The statement a) permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, b) clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133, c) establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, d) clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives, and e) amends SFAS No. 140 to eliminate the prohibition on a qualifying special purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. This statement is effective for all financial instruments acquired or issued after the beginning of an entity’s first fiscal year that begins after September 15, 2006 with early adoption permitted. The Trust is currently assessing the impact of SFAS No. 155.

In June 2006, the FASB issued Interpretation 48 “Accounting for Uncertainty in Income Taxes” clarifying the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. It also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. Interpretation 48 is effective for fiscal years beginning on/after December 15, 2006. The Trust is currently assessing the impact of Interpretation 48.

In September 2006, the FASB issued SFAS 157 “Fair Value Measurements”. The Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands

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disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements. The Statement is to be applied prospectively and is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Trust is currently assessing the impact of SFAS 157.

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115.” This pronouncement permits entities to use the fair value method to measure certain financial assets and liabilities by electing an irrevocable option to use the fair value method at specified election dates. After election of the option, subsequent changes in fair value would result in the recognition of unrealized gains or losses as period costs during the period the change occurred. SFAS No. 159 becomes effective as of the beginning of the first fiscal year that begins after November 15, 2007, with early adoption permitted. However, entities may not retroactively apply the provisions of SFAS No. 159 to fiscal years preceding the date of adoption. The Trust is currently assessing the impact of SFAS 159.

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934

I, William E. Andrew, certify that:

1. I have reviewed this annual report on Form 40-F of Penn West Energy Trust;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 26, 2007

/s/ William E. Andrew

William E. Andrew
President and Chief Executive Officer of Penn West Petroleum Ltd.

Exhibit 99.6

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934

I, Todd Takeyasu, certify that:

1. I have reviewed this annual report on Form 40-F of Penn West Energy Trust;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 26, 2007

/s/ Todd Takeyasu
Todd Takeyasu
Senior Vice President and and Chief Financial Officer of Penn West Petroleum Ltd.

Exhibit 99.7

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn West Energy Trust (the "Trust") on Form 40-F for the year ended December 31, 2006, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William E. Andrew, President and Chief Executive Officer of Penn West Petroleum Ltd., who performs the same function for the Trust, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ William E. Andrew

William E. Andrew
President and Chief Executive Officer of Penn West Petroleum Ltd.

March 26, 2007

Exhibit 99.8

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn West Energy Trust (the "Trust") on Form 40-F for the year ended December 31, 2006, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Todd Takeyasu, Senior Vice President and Chief Financial Officer of Penn West Petroleum Ltd., who performs the same function for the Trust, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ Todd Takeyasu

Todd Takeyasu
Senior Vice President and Chief Financial Officer of Penn West Petroleum Ltd.

March 26, 2007

Exhibit 99.9



KPMG LLP
Chartered Accountants
2700-205 5 Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Telefax (403) 691-8008
Internet www.kpmg.ca

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the board of directors of Penn West Petroleum Ltd., the administrator of Penn West Energy Trust

We consent to the inclusion in this Annual Report on Form 40-F of:

- our audit report dated February 28, 2007 on the consolidated balance sheets of Penn West Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of income and retained earnings and cash flows for the years then ended, and

- our audit report dated February 28, 2007 (except for note (a), which is dated March 26, 2007) on the Supplemental Note to the Consolidated Financial Statements entitled “Reconciliation of Canadian and United States Generally Accepted Accounting Principles”.

each of which is contained in this Annual Report on Form 40-F for the fiscal year ended December 31, 2006.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 27, 2007

KPMG LLP, a Canadian limited liability partnership is the Canadian member firm of KPMG International, a Swiss cooperative

Exhibit 99.10

GLJ Petroleum Consultants

Principal Officers:

Harry Jung, P. Eng.
President, C.E.O.
Dana B. Laustsen, P. Eng.
Executive V.P., C.O.O.
Keith M. Braaten, P. Eng.
Executive V.P.

Officers / Vice Presidents:

Terry L. Aarsby, P. Eng.
Jodi L. Anhorn, P. Eng.
Neil I. Dell, P. Eng.
David G. Harris, P. Geol.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

LETTER OF CONSENT

TO: Penn West Energy Trust

Re: Registration Statement on Form 40-F

Ladies and Gentleman:

We hereby consent to the reference to our firm name and to the inclusion of references to, and excerpts from, our report dated February 28, 2007, evaluating the crude oil, natural gas liquids and natural gas reserves attributed to the properties of Penn West Energy Trust as of December 31, 2006 (the "**GLJ Report**") in the Annual Report on Form 40-F of Penn West Energy Trust for the fiscal year ended December 31, 2006, filed under the Securities Exchange Act of 1934, as amended.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Dana B. Laustsen
Dana B. Laustsen, P. Eng.
Executive Vice-President

Dated: March 16, 2007
Calgary, Alberta
CANADA