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, 2007

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) 777-2500
(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: 242,663,164

Indicate by check mark whether Penn West 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 Penn West in connection with such rule.

Yes o No x

Indicate by check mark whether Penn West: (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 Penn West 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, 2007;

(b) Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2007;

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2007; 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, 2007, 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 Chief Executive Officer ("CEO") and the Executive 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) Management's Annual Report on Internal Control Over Financial Reporting.

Management is responsible for establishing and maintaining adequate internal control over Penn West's financial reporting. Penn West's internal control system was designed to provide reasonable assurance that all transactions are accurately recorded, that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that Penn West's assets are safeguarded.

Management has assessed the effectiveness of Penn West's internal control over financial reporting as at December 31, 2007. In making its assessment, management used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of Penn West's internal control over financial

reporting. Based on this assessment, management has concluded that Penn West's internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of Penn West's internal control over financial reporting as at December 31, 2007 has been audited by KPMG LLP, as stated in their Report of Independent Registered Public Accounting Firm on Penn West's internal control over financial reporting that accompanies Penn West's Consolidated Financial Statements for the fiscal year ended December 31, 2007, filed as Exhibit 99.3 to this Annual Report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the Report of Independent Registered Public Accounting Firm on Penn West's internal control over financial reporting that accompanies Penn West's Consolidated Financial Statements for the fiscal year ended December 31, 2007, filed as Exhibit 99.3 to this Annual Report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2007, 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 2007 and 2006:

(CDN$)	2007	2006
Audit Fees	$ 1,045,000	$ 610,000
Audit-Related Fees	120,000	105,000
Tax Fees	7,914	18,341
All Other Fees	—	—
Total	$ 1,172,914	$ 733,341

Audit Fees. Audit fees consist of fees for the integrated audit of Penn West's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements, reviews in connection with acquisitions and Sarbanes-Oxley Act related services.

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 2007 and 2006, the services provided in this category included French translation services.

Tax Fees. Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2007 and 2006, the services provided in this category included assistance and advice in relation to the communication of the taxability of distributions to unitholders and the review 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.

		Payment due by period			
(CDN$ millions) Contractual Obligations	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
Transportation	39.9	16.2	12.6	4.7	6.4
Power Infrastructure	30.6	6.2	8.4	8.4	7.6
Drilling rigs	11.3	7.7	3.6	—	—
Purchase obligations (1)	107.5	13.3	26.6	26.5	41.1
Office lease	193.3	19.4	36.9	32.7	104.3
Long term debt (2)(3)	1,943.2	—	1,485.4	—	457.8
Asset retirement obligations (4)	1,526.0	41.4	82.8	82.8	1,319.0
Total	**3,851.8**	**104.2**	**1,656.3**	**155.1**	**1,936.2**

(1) These amounts represent estimated commitments of $84.4 million for CO_2 purchases and $23.1 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: James C. Smith, James E. Allard, Shirley A. McClellan and Frank Potter.

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, the Chairman of the Board, 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.

Membership on Multiple Audit Committees

Section 303A.07 of the NYSE's Listed Company Manual requires that if an audit committee member simultaneously serves on the audit committees of more than three public companies, and if the listed company does not limit the number of audit committees on which its audit committee members may serve to three or less, the Board of Directors of the listed company must determine that such simultaneous service would not impair the ability of the audit committee member to effectively serve on the listed company's audit committee, and must publicly disclose such determination. James C. Smith, a member of Penn West's audit committee, serves on the audit committees of more than three public companies. Penn West's Board of Directors has determined that such simultaneous service would not impair Mr. Smith's ability to effectively serve on Penn West's audit committee.

Frank Potter, another member of Penn West's audit committee, also serves on the audit committee of more than three public companies. Penn West's Board of Directors has not yet made a determination as to whether or not such simultaneous service would impair the ability of Mr. Potter to effectively serve on Penn West's audit committee. Penn West has disclosed the fact that such a determination has not yet been made in the NYSE Statement of Governance Differences that appears on Penn West's website (www.pennwest.com).

Communication with Non-Management Directors

Unitholders may send communications to Penn West's non-management directors by writing to George H. Brookman, Chairman of the Governance Committee of the Board of Directors, 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, 2008.

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

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

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the fiscal year ended December 31, 2007
99.2	Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2007
99.3	Consolidated Financial Statements for the fiscal year ended December 31, 2007
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.
99.11	Consent of Sproule Associates Limited

Exhibit 99.1

PENN WEST ENERGY TRUST

PENN WEST ENERGY TRUST

Annual Information Form
for the year ended December 31, 2007

March 26, 2008

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- Appendix A-1 – Report of Management and Directors on Reserves Data and Other Information
- Appendix A-2 – GLJ Report on Reserves Data
- Appendix A-3 – Statement of Reserves Data – Penn West Energy Trust

APPENDIX "B" – CANETIC RESOURCES TRUST RESERVES DISCLOSURE
- Appendix B-1 – Report of Management and Directors on Reserves Data and Other Information
- Appendix B-2 – Sproule Report on Reserves Data
- Appendix B-3 – Statement of Reserves Data – Canetic Resources Trust

APPENDIX "C" – MANDATE OF THE AUDIT COMMITTEE

GLOSSARY OF TERMS

The following is a glossary of certain terms used in this Annual Information Form.

"**6.5% 2005 Debenture Indenture**" means the trust indenture governing the 6.5% 2005 Debentures.

"**6.5% 2005 Debentures**" means the 6.5% convertible, extendible, unsecured, subordinated debentures issued on May 26, 2005 pursuant to the 6.5% 2005 Debenture Indenture, which debentures were assumed by Penn West pursuant to the Canetic Acquisition and subsequently began trading on the TSX as securities of Penn West on January 16, 2008 under the symbol PWT.DB.D.

"**6.5% 2006 Debenture Indenture**" means the trust indenture governing the 6.5% 2006 Debentures.

"**6.5% 2006 Debentures**" means the 6.5% convertible, extendible, unsecured, subordinated debentures issued on August 24, 2006 pursuant to the 6.5% 2006 Debenture Indenture, which debentures were assumed by Penn West pursuant to the Canetic Acquisition and subsequently

began trading on the TSX as securities of Penn West on January 16, 2008 under the symbol PWT.DB.F.

"**7.2% Debenture Indenture**" means the trust indenture governing the 7.2% Debentures.

"**7.2% Debentures**" means the 7.2% convertible, unsecured, subordinated debentures issued on May 2, 2006 pursuant to the 7.2% Debenture Indenture, which debentures were assumed by Penn West pursuant to the Vault Acquisition and subsequently began trading on the TSX as securities of Penn West on January 15, 2008 under the symbol PWT.DB.E.

"**8% 2004 Debenture Indenture**" means the trust indenture governing the 8% 2004 Debentures.

"**8% 2004 Debentures**" means the 8% convertible, extendible, unsecured, subordinated debentures issued on June 15, 2004 pursuant to the 8% 2004 Debenture Indenture, which debentures were assumed by Penn West pursuant to the Canetic Acquisition and subsequently began trading on the TSX as securities of Penn West on January 16, 2008 under the symbol PWT.DB.B.

"**8% 2005 Debenture Indenture**" means the trust indenture governing the 8% 2005 Debentures.

"**8% 2005 Debentures**" means the 8% convertible, unsecured, subordinated debentures issued on June 22, 2005 pursuant to the 8% 2005 Debenture Indenture, which debentures were assumed by Penn West pursuant to the Vault Acquisition and subsequently began trading on the TSX as securities of Penn West on January 15, 2008 under the symbol PWT.DB.C.

"**9.4% Debenture Indenture**" means the trust indenture governing the 9.4% Debentures.

"**9.4% Debentures**" means the 9.4% convertible, unsecured, subordinated debentures issued on July 3, 2003 pursuant to the 9.4% Debenture Indenture, which debentures were assumed by Penn West pursuant to the Canetic Acquisition and subsequently began trading on the TSX as securities of Penn West on January 16, 2008 under the symbol PWT.DB.A.

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, C. B-9, as amended, including the regulations promulgated thereunder.

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

"**Board of Directors**" means the Board of Directors of PWPL.

"**Canetic**" means Canetic Resources Trust, a trust established under the laws of the Province of Alberta.

"**Canetic Acquisition**" means the plan of arrangement under the ABCA pursuant to which Penn West acquired Canetic on January 11, 2008.

"**CBM**" means coalbed methane.

"**Convertible Debentures**" means, collectively, the 6.5% 2005 Debentures, the 6.5% 2006 Debentures, the 7.2% Debentures, the 8% 2004 Debentures, the 8% 2005 Debentures and the 9.4% Debentures.

"**Debenture Indentures**" means, collectively, the 6.5% 2005 Debenture Indenture, the 6.5% 2006 Debenture Indenture, the 7.2% Debenture Indenture, the 8% 2004 Debenture Indenture, the 8% 2005 Debenture Indenture and the 9.4% Debenture Indenture.

"**Debenture Trustee**" means, in respect of the 6.5% 2005 Debentures, Olympia Trust Company, in respect of each of the 6.5% 2006 Debentures, the 8% 2004 Debentures and the 9.4% Debentures, Computershare Trust Company of Canada, and in respect of each of the 7.2% Debentures and the 8% 2005 Debentures, Canadian Western Trust Company.

"**GAAP**" means Canadian generally accepted accounting principles.

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

"**GLJ Report**" means the report prepared by GLJ dated February 20, 2008 evaluating the crude oil, natural gas and natural gas liquids reserves and the net present value of future net revenue attributable to certain of Penn West's oil and natural gas assets effective as at December 31, 2007.

"**Gross**" means:

(a) in relation to our interest in production or reserves, our working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests 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.

"**Internal Notes**" means the unsecured subordinated promissory notes issued by PWPL and certain other Operating Entities to Penn West as at January 11, 2008 following the completion of the Vault Acquisition and the Canetic Acquisition.

"**Net**" means:

(a) in relation to our interest in production or reserves, our working interest (operating or non-operating) share after deduction of

royalty obligations, plus our royalty interests in production or reserves;

(b) in relation to our interest in 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.

"**NI 51-101**" means National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

"**Non-Resident**" means: (i) a person who is not a resident of Canada for the purposes of the Tax Act; or (ii) a partnership that is not a Canadian partnership for the purposes of the Tax Act.

"**NPI Agreements**" means the net profits interest agreements between Penn West and certain of Penn West's Operating Entities and to which Penn West is a party as of or prior to January 11, 2008 following completion of the Vault Acquisition and the Canetic Acquisition.

"**NPIs**" means the net profits interests granted to Penn West under the NPI Agreements.

"**NYSE**" means the New York Stock Exchange.

"**Operating Entities**" means, from and after February 1, 2008 following the completion of the Vault Acquisition, the Canetic Acquisition and subsequent internal reorganizations, collectively, PWPL, Penn West Partnership, Canetic ABC Limited Partnership, Titan Canada Resources, Canetic Resources Partnership, Petrofund Ventures Trust, Tika Energy Inc. and Upton Resources Inc., each a direct or indirect wholly-owned subsidiary of Penn West, and "**Operating Subsidiary**" means any one of them, as applicable.

"**Operating Entities Securities**" means the Internal Notes, the NPIs, the common shares of PWPL and any other securities of the Operating Entities owned, directly or indirectly, by Penn West.

"**Penn West**", "**we**", "**us**", "**our**" or "**Trust**" means Penn West Energy Trust, a trust established under the laws of the Province of Alberta pursuant to the Trust Indenture. Where the context requires, these terms also include all of Penn West's Subsidiaries on a consolidated basis, which in the case of information presented as at or after January 10, 2008 includes Vault and Vault's former Subsidiaries (if the context requires), and in the case of information presented as at or after January 11, 2008 includes Canetic and Canetic's former Subsidiaries (where the context requires).

"**Penn West Partnership**" means Penn West Petroleum, a general partnership, the partners of which are PWPL, Trocana Resources Inc., Canetic Saskatchewan Trust, 990009 Alberta Inc. and 1167639 Alberta Ltd. effective from and after January 11, 2008 following the completion of the Vault Acquisition and the Canetic Acquisition.

"**Petrofund**" means Petrofund Energy Trust, a trust established under the laws of the Province of Ontario.

"**Petrofund Acquisition**" means the plan of arrangement under the ABCA pursuant to which Penn West acquired Petrofund on June 30, 2006.

"**PWPL**" means Penn West Petroleum Ltd., a corporation amalgamated under the ABCA, a wholly-owned subsidiary of Penn West and the administrator of Penn West pursuant to the Administration Agreement.

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

"**Sproule Canetic Report**" means the report prepared by Sproule dated March 3, 2008 evaluating the crude oil, natural gas and natural gas liquids reserves and the net present value of future net revenue attributable to certain of Canetic's oil and natural gas assets effective as at December 31, 2007.

"**Sproule Vault Report**" means the report prepared by Sproule dated March 3, 2008 evaluating the crude oil, natural gas and natural gas liquids reserves and the net present value of future net revenue attributable to certain of Vault's oil and natural gas assets effective as at December 31, 2007.

"**Subsidiaries**" has the meaning ascribed thereto in the *Securities Act* (Ontario) and, for greater certainty, includes all corporations, partnerships and trusts owned, controlled or directed, directly or indirectly, by Penn West.

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, C. 1 (5th Supp.), as amended, including the regulations promulgated thereunder, as amended from time to time.

"**Titan**" means Titan Exploration Ltd., a corporation amalgamated under the ABCA.

"**Trust Indenture**" means the amended and restated trust indenture between the Trustee and PWPL, amended and restated as of June 30, 2006.

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

"**Trustee**" means CIBC Mellon Trust Company, our trustee.

"**TSX**" means the Toronto Stock Exchange.

"**United States**" or "**US**" means the United States of America.

"**Unitholders**" means holders of our Trust Units.

"**undeveloped land**" and "**unproved property**" each mean a property or part of a property to which no reserves have been specifically attributed.

"**Vault**" means Vault Energy Trust, a trust established under the laws of the Province of Alberta.

"**Vault Acquisition**" means the plan of arrangement under the ABCA pursuant to which Penn West acquired Vault on January 10, 2008.

CONVENTIONS

Certain terms used herein are defined in the "Glossary of Terms". Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. References herein to "US$" are to United States dollars.

All financial information herein has been presented in Canadian dollars in accordance with Canadian GAAP.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel or barrels
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
NGLs	natural gas liquids
MMboe	million barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day

Natural Gas

GJ	gigajoule
Gj/d	gigajoules per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
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, the reference price paid in United States dollars at Cushing, Oklahoma for crude oil of standard grade.
API	means American Petroleum Institute.
°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$	means one million dollars.
MW	means megawatt.
MWh	means megawatt hour.
CO_2	means carbon dioxide.

Where any disclosure of reserves data is made in this Annual Information Form (including the Appendices hereto) that does not reflect all reserves of Penn West or Canetic, as the case may be, the reader should note that 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 effects of aggregation.

References in this Annual Information Form to undeveloped land and unproved properties held, owned or acquired by us, or in respect of which we have an interest, refer to undeveloped land or unproved properties in respect of which we have a lease or other contractual right to explore for, develop and exploit hydrocarbons underlying such undeveloped land or unproved properties.

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	2.500
gigajoules (at standard)	MMbtu	0.950
MMbtu (at standard)	gigajoules	1.053
gigajoules (at standard)	Mcf	1.055

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

In the interest of providing Unitholders and potential investors with information regarding Penn West, including management's assessment of Penn West's future plans and operations, certain statements contained and incorporated by reference 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 and the documents incorporated by reference herein contain, without limitation, forward-looking statements pertaining to the following: the performance characteristics of our oil and natural gas properties; the impact on our business, distribution policies and Unitholders of the SIFT Tax (as defined herein) and the different actions that we might take in response to the SIFT Tax; the impact on our reserves and business of the proposed new Alberta royalty framework; environmental regulation compliance costs and strategy; oil and natural gas production level estimates; netback estimates; our business strategy, including our strategy in respect of our Peace River Oil Sands project, and our coal bed methane, shale gas and enhanced oil recovery projects; our product balance; the sufficiency of our environmental program; funding sources for distributions and distribution levels; the funding of our asset retirement obligations; our outlook for oil and natural gas prices; our forecast 2008 net capital expenditures and the allocation and funding thereof; our exploration and development plans for our oil and natural gas properties in 2008 and beyond; currency exchange rates; our forecast funds flow; the nature and effectiveness of our risk management strategies; our belief that we will be successful in renewing or replacing our credit facilities on acceptable terms when they expire; the quantity and recoverability of our oil and natural gas reserves and resources; and our ability to economically develop our contingent resources at our Peace River Oil Sands project and convert these resources into reserves.

With respect to forward-looking statements contained or incorporated by reference in this document, we have made assumptions regarding, among other things: future capital expenditure levels; 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; 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 or incorporated by reference 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 or incorporated by reference 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 our ability to execute capital programs; risks inherent in oil and natural 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 US 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 acquisition of Canetic and Vault; changes in federal and provincial taxation laws and regulations;

changes in the Alberta royalty framework and their impact on us; uncertainty of obtaining required approvals in respect of acquisitions and mergers; and the other factors described under "Risk Factors" in this document and in Penn West's public filings 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 and incorporated by reference 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 and incorporated by reference in this document are expressly qualified by this cautionary statement.

NON-GAAP MEASURES

This Annual Information Form refers to funds flow and funds flow from operations derived from cash flow from operating activities. Funds 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. Funds flow as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Funds 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 GAAP.

For more information, see Penn West's Management's Discussion and Analysis for the year ended December 31, 2007, which includes a reconciliation of "funds flow" to cash flow from operating activities, which has been filed on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

EFFECTIVE DATE OF INFORMATION

Except where otherwise indicated, the information in this Annual Information Form is presented as at the end of Penn West's most recently completed financial year, being December 31, 2007, which is prior to Penn West's acquisition of Vault and Canetic.

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 Penn West 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 ABCA. Pursuant to this plan of arrangement, holders of common shares of PWPL received three (3) Trust Units for each one (1) of their common shares.

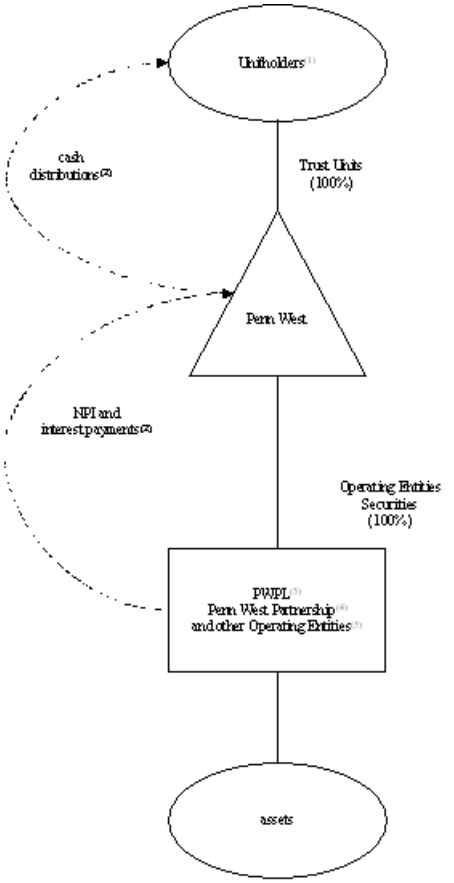
Inter-Corporate Relationships

The following are the names, the percentage of votes attaching to all voting securities beneficially owned, or controlled or directed, directly or indirectly, by Penn West, and the jurisdiction of incorporation, continuance, formation or organization of our direct and indirect material Subsidiaries as at February 1, 2008 following the completion of the Vault Acquisition, the Canetic Acquisition and subsequent internal reorganizations.

	Percentage of Votes	Nature of Entity	Jurisdiction of Incorporation/ Formation
Penn West Petroleum Ltd.	100%	Corporation	Alberta
Penn West Petroleum	100%	General Partnership	Alberta

Our Organizational Structure

The following diagram sets forth the simplified organizational structure of Penn West as at February 1, 2008 following the completion of the Vault Acquisition, the Canetic Acquisition and subsequent internal reorganizations.



Notes:

(1) The Unitholders own 100 percent of Penn West's equity.

(2) Cash distributions are made on a monthly basis to Unitholders based upon, among other things, our funds flow. Our primary sources of funds flow are payments from PWPL and our other Operating Entities pursuant to the NPIs and interest on the principal amount of the Internal Notes.

(3) PWPL as it presently exists was formed effective as of January 11, 2008 as part of the completion of the Canetic Acquisition pursuant to the amalgamation of Penn West Petroleum Ltd., Titan, Penn West Canetic Acquisition Ltd., Canetic Resources Inc., Trend Energy Inc., 1336953 Alberta Ltd., 1141702 Alberta Ltd. and Vault Energy Inc.

(4) PWPL, Trocana Resources Inc., Canetic Saskatchewan Trust, 990009 Alberta Inc. and 1167639 Alberta Ltd. are the partners of Penn West Partnership effective as of January 11, 2008 following the completion of the Vault Acquisition and the Canetic Acquisition.

(5) The other Operating Entities are direct or indirect wholly-owned subsidiaries of Penn West. Other than PWPL and the Penn West Partnership, Penn West does not have any subsidiaries: (i) the total assets of which exceed 10% of Penn West's consolidated assets (or 20% of Penn West's consolidated assets when aggregated with all other subsidiaries of Penn West other than PWPL and the Penn West Partnership); or (ii) the sales and operating revenues of which exceed 10% of Penn West's consolidated sales and operating revenues (or 20% of Penn West's consolidated sales and operating revenues when aggregated with all other subsidiaries of Penn West other than PWPL and the Penn West Partnership).

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

Year Ended December 31, 2005

PWPL Trust Conversion

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

Acquisitions and Dispositions

We completed property dispositions, net of acquisitions, of $5.8 million in 2005. We did not complete any corporate acquisitions in 2005.

Year Ended December 31, 2006

NYSE Listing

On June 22, 2006, the Trust Units were listed on the NYSE.

Petrofund Acquisition

Effective June 30, 2006, Penn West completed the Petrofund Acquisition, pursuant to which Penn West acquired Petrofund on the basis of an exchange of 0.60 of a Trust Unit for each one (1) trust unit of Petrofund. An aggregate of approximately 70.7 million Trust Units were issued. A special cash distribution in the amount of $1.10 per trust unit of Petrofund, 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 Acquisition to the holders of trust units of Petrofund. An aggregate of $129.6 million was distributed. As a result of the Petrofund Acquisition, 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, 93.8 MMbbl of light/medium crude oil and NGLs, 1.0 MMbbl of heavy oil and 371.2 Bcf of natural gas on a proved plus probable reserve basis, and 352,600 net acres of undeveloped land. Penn West also assumed $610.4 million of bank indebtedness of Petrofund in connection with the Petrofund Acquisition.

Acquisitions and Dispositions

We completed property acquisitions, net of dispositions, of $5.6 million in 2006. Other than the Petrofund Acquisition described above, we did not complete any corporate acquisitions in 2006.

Year Ended December 31, 2007

April 2007 Asset Acquisition

On April 11, 2007, Penn West completed the acquisition (the "**April 2007 Asset Acquisition**") of certain conventional oil and natural gas assets for cash consideration of approximately $329 million. The assets were located primarily in the Province of Alberta and included assets situated within or near Penn West's Peace River oil sands project and its adjacent holdings in the Red Earth/Utikuma area. As a result of the acquisition, Penn West acquired 6.4 MMbbl of light/medium crude oil and NGLs, 0.1 MMbbl of heavy oil and 15.6 Bcf of natural gas on a proved reserve basis, 8.1 MMbbl of light/medium crude oil and NGLs, 0.1 MMbbl of heavy oil and 21.9 Bcf of natural gas on a proved plus probable reserve basis, and 190,000 net acres of undeveloped land. The acquisition was financed using Penn West's existing syndicated credit facility and a new $250 million unsecured, demand credit facility.

Private Placement of Notes

Effective May 31, 2007, PWPL completed the private placement of an aggregate of US$475 million principal amount of notes. The private placement consisted of the issuance of US$160 million principal amount of 5.68 percent notes due in 2015, US$155 million principal amount of 5.80 percent notes due in 2017, US$140 million principal amount of 5.90 percent notes due in 2019 and US$20 million principal amount of 6.05 percent notes due in 2022. The notes are unsecured and rank equally with Penn West's bank credit facilities. The proceeds of the notes were used to repay a portion of the indebtedness under Penn West's bank credit facilities.

Acquisitions and Dispositions

In addition to the April 2007 Asset Acquisition described above, we completed property acquisitions, net of dispositions, of $92.7 million in 2007. We also completed one corporate acquisition for total cash consideration of $21.2 million resulting in total acquisitions, net of dispositions, of $442.9 million in 2007 (including the April 2007 Asset Acquisition).

Recent Developments

Vault Acquisition

Effective January 10, 2008, Penn West completed the Vault Acquisition, pursuant to which Penn West acquired Vault on the basis of an exchange of 0.14 of a Trust Unit for each one (1) trust unit of Vault, 0.14 of a Trust Unit for each one (1) trust unit of Vault into which the Series A exchangeable shares of Vault Energy Inc. were exchangeable, and a payment of $0.51 for each one (1) warrant to purchase a trust unit of Vault. An aggregate of approximately 5.6 million Trust Units were issued and an aggregate of approximately $768,111 was paid. As a result of the Vault Acquisition, and based on the Sproule Vault Report, Penn West acquired 7.8 MMbbl of light/medium crude oil and NGLs and 49.5 Bcf of natural gas on a proved reserve basis, and 10.1 MMbbl of light/medium crude oil and NGLs and 71.6 Bcf of natural gas on a proved plus probable reserve basis. Penn West also acquired 125,000 net acres of undeveloped land.

Penn West also assumed approximately $89 million of bank indebtedness of Vault, $50 million principal amount of 7.2% Debentures issued by Vault and $48.7 million principal amount of 8% 2005 Debentures issued by Vault in connection with the Vault Acquisition. On March 5, 2008, Penn West repurchased for cancellation $23.8 million principal amount of the 7.2% Debentures and $11,000 principal amount of the 8% 2005 Debentures pursuant to issuer bids required by the 7.2% Debenture Indenture and the 8% 2005 Debenture Indenture, respectively.

Canetic Acquisition

Effective January 11, 2008, Penn West completed the Canetic Acquisition, pursuant to which Penn West acquired Canetic on the basis of an exchange of 0.515 of a Trust Unit for each one (1) trust unit of Canetic. An aggregate of approximately 124.3 million Trust Units were issued. In addition, a special cash distribution in the amount of $0.09 per trust unit of Canetic was made to holders of trust units of Canetic of record at the close of business on January 10, 2008. An aggregate of approximately $21.7 million was distributed to Canetic unitholders on January 15, 2008.

As a result of the Canetic Acquisition, based on the Sproule Canetic Report, Penn West acquired 92.0 MMbbl of light/medium crude oil and NGLs, 15.1 MMbbl of heavy oil and 403.2 Bcf of natural gas on a proved reserve basis and 127.2 MMbbl of light/medium crude oil and NGLs, 19.4 MMbbl of heavy oil and 597.9 Bcf of natural gas on a proved plus probable reserve basis. Penn West also acquired 774,000 net acres of undeveloped land. For detailed disclosure of the Sproule Canetic Report and other oil and gas information of Canetic in accordance with NI 51-101, see Appendix B hereto.

Penn West assumed approximately $1.4 billion of bank indebtedness of Canetic, $17.8 million principal amount of 6.5% 2005 Debentures issued by Canetic, $229.6 million principal amount of 6.5% 2006 Debentures issued by Canetic, $8.0 million principal amount of 8% 2004 Debentures issued by Canetic, and $5.6 million principal amount of 9.4% Debentures issued by Canetic in connection with the Canetic Acquisition.

In connection with the Canetic Acquisition, the Board of Directors of PWPL was reconstituted to include eight members of PWPL's then existing board and four members of Canetic's then existing board. In addition, in connection with and following the completion of the Canetic Acquisition, PWPL's management team was reconstituted to, among other things,

include certain former officers of Canetic. For detailed information regarding the current directors and officers of PWPL, see "Corporate Governance – Directors and Officers" below.

Concurrent with the closing of the Canetic Acquisition, Penn West secured a $4 billion credit facility for a three-year term with a syndicate of 18 Canadian and international banks. The new credit facility was initially used to retire Penn West's indebtedness under its then existing bank credit facilities and to retire all bank indebtedness assumed by Penn West in connection with the Vault Acquisition and the Canetic Acquisition.

Significant Acquisitions

There were no significant acquisitions completed by Penn West during the financial year ended December 31, 2007 for which disclosure was required under Part 8 of National Instrument 51-102. However, the completion of the Canetic Acquisition on January 11, 2008 constituted a significant acquisition for which disclosure was required under Part 8 of National Instrument 51-102. For a description of the Canetic Acquisition, see "General Development of the Business – History and Development – Canetic Acquisition" above. Penn West has also filed a Form 51-102F4 – Business Acquisition Report in respect of the Canetic Acquisition.

DESCRIPTION OF OUR BUSINESS

Overview

Our principal undertaking is to issue Trust Units and to acquire and hold securities of Subsidiaries, net profits interests, royalties, notes and other interests. Our direct and indirect Subsidiaries 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 funds flow from the assets is paid from PWPL and our other Operating Entities to us by way of interest and principal payments on the Internal Notes and payments 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 PWPL and our other Operating Entities by way of interest received on the principal amount of the Internal Notes and payments pursuant to the NPIs. 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.

As at February 29, 2008, we had approximately 1,850 employees and full time consultants.

PWPL

PWPL is a corporation amalgamated and subsisting pursuant to the laws of Alberta. PWPL 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 PWPL. The registered and head office of PWPL is located at 2200, 425 – 1st Street S.W., Calgary, Alberta, T2P 3L8.

Internal Notes

The Internal Notes evidence the indebtedness of PWPL and certain other Operating Entities to Penn West. The Internal Notes are payable on demand, are unsecured, and are subordinated to senior indebtedness and bear interest at rates ranging from six percent per annum to 13 percent per annum and require principal payments at dates ranging from May 31, 2017 to January 1, 2019.

NPIs

The Trust is a party to NPI Agreements with PWPL and certain other Operating Entities pursuant to which we have the right to receive the NPIs on petroleum and natural gas rights held by PWPL and the other Operating Entities from time to time. Pursuant to the terms of the agreements, we are entitled to a payment from PWPL and the other Operating Entities 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 PWPL and the other Operating Entities for such month exceeds

99 percent of certain deductible costs for such period. Deductible costs generally include capital expenditures, royalties, operating costs and certain interest expenses related to oil and gas activities. The term of the agreements is for as long as there are petroleum and natural gas rights to which the NPIs apply.

Pro Forma Reserves Data of Penn West, Canetic and Vault

The pro forma reserves data set forth below is an aggregate roll-up of Penn West's reserves data, Canetic's reserves data and Vault's reserves data. Penn West's reserves data is based upon an evaluation prepared by GLJ with an effective date of December 31, 2007 contained in the GLJ Report dated February 20, 2008. Canetic's reserves data is based on an evaluation prepared by Sproule with an effective date of December 31, 2007 contained in the Sproule Canetic Report dated March 3, 2008. Vault's reserves data is based upon an evaluation prepared by Sproule with an effective date of December 31, 2007 contained in the Sproule Vault Report dated March 3, 2008. Each of the aforementioned reports was prepared in accordance with NI 51-101.

The pro forma reserves data summarizes Penn West's, Canetic's and Vault's oil, natural gas liquid and natural gas reserves and net present values of future net revenue from these reserves using forecast prices and costs, not including the effect of any hedging activities, as at December 31, 2007 assuming that all reserves were held by Penn West at that time. The same forecast price and cost assumptions were used in the GLJ Report, the Sproule Canetic Report and the Sproule Vault Report. For information respecting the forecast price and cost assumptions used and other relevant information, see "Notes to Reserves Data Tables" in Appendix A-3 Statement of Reserves Data – Penn West Energy Trust and in Appendix B-3 Statement of Reserves Data – Canetic Resources Trust.

See Appendices A-1, A-2 and A-3 for complete NI 51-101 oil and gas reserves disclosure for Penn West on a "stand-alone" basis as at December 31, 2007. See Appendices B-1, B-2 and B-3 for select NI 51-101 oil and gas reserves disclosure for Canetic on a "stand-alone" basis as at December 31, 2007. See "General Development of the Business – History and Development – Vault Acquisition" for certain summary information in respect of Vault's oil and gas reserves as at December 31, 2007 that is derived from the Sproule Vault Report.

The GLJ Report, the Sproule Canetic Report and the Sproule Vault Report do not take into account the new Alberta royalty regime released on October 25, 2007 titled *"The New Royalty Framework"*, which is scheduled to take effect on January 1, 2009, because sufficient details are not yet available for it to be taken into account. See "Risk Factors – New Alberta Royalty Regime".

All of the pro forma reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba, other than some minor interests in the United States that Penn West acquired from Canetic pursuant to the Canetic Acquisition.

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 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 and Resource Estimates" and "Risk Factors – Volatility of Oil and Natural Gas Prices".

PRO FORMA SUMMARY OF
PENN WEST, CANETIC AND VAULT OIL AND GAS RESERVES
as of December 31, 2007
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (MMbbl)	Net (MMbbl)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	233.5	212.0	56.1	50.8
Developed Non-Producing	5.3	5.0	3.0	2.6
Undeveloped	38.7	34.8	1.5	1.4
TOTAL PROVED	277.5	251.8	60.6	54.7
PROBABLE	89.7	80.3	20.6	18.3
TOTAL PROVED PLUS PROBABLE	367.2	332.0	81.2	73.1

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Bcf)	Net (Bcf)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	1,027.2	830.4	27.1	19.0
Developed Non-Producing	66.3	52.4	1.4	0.9
Undeveloped	62.2	49.3	1.4	0.9
TOTAL PROVED	1,155.7	932.1	29.9	20.9
PROBABLE	414.6	333.0	10.2	7.3
TOTAL PROVED PLUS PROBABLE	1,570.3	1,265.1	40.1	28.2

RESERVES CATEGORY	RESERVES TOTAL OIL EQUIVALENT Gross (MMboe)	 Net (MMboe)
PROVED		
Developed Producing	487.9	420.1
Developed Non-Producing	20.8	17.3
Undeveloped	52.0	45.4
TOTAL PROVED	560.6	482.8
PROBABLE	189.7	161.4
TOTAL PROVED PLUS PROBABLE	750.2	644.2

PRO FORMA
NET PRESENT VALUES OF FUTURE NET REVENUE OF PENN WEST, CANETIC AND VAULT
BEFORE INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS(1)

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED					
Developed Producing	16,693	11,825	9,424	7,965	6,969
Developed Non-Producing	669	445	339	275	231
Undeveloped	2,053	1,102	679	451	313
TOTAL PROVED	19,415	13,372	10,442	8,691	7,512
PROBABLE	7,374	3,713	2,333	1,652	1,256
TOTAL PROVED PLUS PROBABLE	26,790	17,085	12,774	10,342	8,768

Note:
(1) Management of PWPL has estimated that the impact of Alberta's Proposed Royalty Regime, in the form currently proposed, is to decrease the pro forma net present values of future net revenue before income taxes by approximately 3 percent to 4 percent using a 10 percent discount rate and using the forecast prices set forth in this Annual Information Form.

PRO FORMA
NET PRESENT VALUES OF FUTURE NET REVENUE OF PENN WEST, CANETIC AND VAULT
AFTER INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED					
Developed Producing	15,298	11,185	9,071	7,749	6,829
Developed Non-Producing	543	376	293	242	207
Undeveloped	1,614	891	560	377	263
TOTAL PROVED	17,455	12,451	9,924	8,368	7,299
PROBABLE	5,612	2,909	1,875	1,359	1,054
TOTAL PROVED PLUS PROBABLE	23,068	15,360	11,798	9,727	8,353

CAPITALIZATION OF PWPL

Common Shares

PWPL 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 PWPL with any other entity, except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iii) any statutory arrangement involving PWPL, except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iv) any amendment to the articles of PWPL to increase or decrease the minimum or maximum number of directors; or (v) any material amendment to the articles of PWPL to change the authorized share capital or amend the

rights, privileges, restrictions and conditions attaching to any class of PWPL'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 PWPL 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 PWPL upon the liquidation, dissolution, bankruptcy or winding-up of PWPL 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

PWPL 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 PWPL 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 PWPL, whether voluntary or involuntary, or any other distribution of the assets of PWPL among its shareholders for the purpose of winding-up its affairs.

The Board of Directors has authorized one series of preferred shares, being the first preferred shares series A (the " **Series A Preferred Shares**"). One thousand Series A Preferred Shares have been authorized for issuance. Holders of Series A Preferred Shares are entitled to receive preferential cash dividends in such amounts as may be declared by the Board of Directors. The payment of such dividends is in priority to dividends on the common shares of PWPL and all other shares ranking junior to the Series A Preferred Shares with respect to the payment of dividends. PWPL has the right to redeem at any time all, or from time to time any part, of the then outstanding Series A Preferred Shares at a price per share equal to $1,000, together with all accrued and unpaid dividends thereon up to the date fixed for redemption. Each registered holder of Series A Preferred Shares is entitled to require PWPL to retract at any time any Series A Preferred Shares tendered at a price per share equal to $1,000, together with all accrued and unpaid dividends thereon up to the retraction date. In the event of the liquidation, dissolution or winding-up of PWPL or other distribution of the assets of PWPL among its shareholders for the purpose of winding-up its affairs, the holders of Series A Preferred Shares are entitled to receive an amount per Series A Preferred Share equal to $1,000 per share, together with any accrued and unpaid dividends to the date of commencement of such event, to be paid all such money before any money shall be paid or property or assets distributed to the holders of any common shares of PWPL or other shares in the capital of PWPL ranking junior to the Series A Preferred Shares with respect to return of capital. After payment of the aforementioned amount, the Series A Preferred Shares shall not be entitled to share in any further distribution of the property or assets of PWPL. So long as any Series A Preferred Shares are outstanding PWPL may not, without the approval of the holders of the Series A Preferred Shares, take certain actions unless all dividends which have been declared have been paid or set apart for payment. Subject to applicable law, the holders of the Series A Preferred Shares are not entitled as such to any voting rights or to receive notice of or to attend any meeting of the shareholders of PWPL or to vote at any such meeting, except for meetings at which holders of a specified class or series of shares of PWPL are entitled or required to vote separately as a class or series pursuant to the provisions of the ABCA.

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 PWPL.

INFORMATION RELATING TO PENN WEST

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 Penn West. 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.

As at March 26, 2008, approximately 374.2 million Trust Units were outstanding, approximately 6.3 million Trust Units were reserved for issuance on conversion of the Convertible Debentures and approximately 25.3 million Trust Units were available for future issuance pursuant to Penn West's trust unit rights incentive plan and employee stock savings plan (subject to increase in accordance with such plans).

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.

Convertible Debentures

Penn West has six series of convertible debentures outstanding, the 6.5% 2005 Debentures, the 6.5% 2006 Debentures, the 7.2% Debentures, the 8% 2004 Debentures, the 8% 2005 Debentures and the 9.4% Debentures. The 7.2% Debentures and the 8% 2005 Debentures were assumed by Penn West pursuant to the Vault Acquisition, which closed on January 10, 2008. The 6.5% 2005 Debentures, the 6.5% 2006 Debentures, the 8% 2004 Debentures and the 9.4% Debentures were assumed by Penn West pursuant to the Canetic Acquisition, which closed on January 11, 2008. The following is a summary of the material attributes and characteristics of the Convertible Debentures.

The 6.5% 2006 Debentures were originally issued in the aggregate principal amount of $230 million and $229.6 million principal amount was outstanding at March 26, 2008. The 6.5% 2006 Debentures mature on December 31, 2011.

The 8% 2004 Debentures were originally issued in the aggregate principal amount of $75 million and approximately $8.0 million principal amount was outstanding at March 26, 2008. The 8% 2004 Debentures mature on August 31, 2009.

The 6.5% 2005 Debentures were originally issued in the aggregate principal amount of $60 million and approximately $17.8 million principal amount was outstanding at March 26, 2008. The 6.5% 2005 Debentures mature on July 31, 2010.

The 9.4% Debentures were originally issued in the aggregate principal amount of $50 million and approximately $5.6 million principal amount was outstanding at March 26, 2008. The 9.4% Debentures mature on July 31, 2008.

The 8% 2005 Debentures were originally issued in the aggregate principal amount of $55 million and approximately $48.7 million principal amount was outstanding at March 26, 2008. The 8% 2005 Debentures mature on June 30, 2010.

The 7.2% Debentures were originally issued in the aggregate principal amount of $50 million and approximately $26.2 million principal amount was outstanding at March 26, 2008. The 7.2% Debentures mature on May 31, 2011.

Terms of Convertible Debentures

The 6.5% 2006 Debentures bear interest from the date of issue at 6.5% per annum, which is payable semi-annually in arrears on June 30 and December 31 in each year. The 8% 2004 Debentures bear interest from the date of issue at 8% per annum, which is payable semi-annually in arrears on February 28 and August 31 in each year. The 6.5% 2005 Debentures bear interest from the date of issue at 6.5% per annum, which is payable semi-annually in arrears on January 31 and July 31 in

each year. The 9.4% Debentures bear interest from the date of issue at 9.4% per annum, which is payable semi-annually in arrears on January 31 and July 31 in each year. The 8% 2005 Debentures bear interest from the date of issue at 8% per annum, which is payable semi-annually in arrears on June 30 and December 31 in each year. The 7.2% Debentures bear interest from the date of issue at 7.2% per annum, which is payable semi-annually in arrears on May 31 and November 30 in each year.

The principal amount of the Convertible Debentures is payable in lawful money of Canada or, at the option of the Trust and subject to applicable regulatory approval, by payment of Trust Units as further described under “Payment Upon Redemption or Maturity” and “Redemption and Purchase”. The interest on the Convertible Debentures is payable in lawful money of Canada and, in the case of certain of the Convertible Debentures, at the option of the Trust and subject to applicable regulatory approval, in accordance with the Interest Obligation as described under “Interest Payment Option”.

The Convertible Debentures are direct obligations of the Trust and are not secured by any mortgage, pledge, hypothec or other charge and are subordinated to other liabilities of the Trust as described under “Subordination”. The indentures governing the Convertible Debentures do not restrict the Trust from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its properties to secure any indebtedness.

Conversion Privilege

The 6.5% 2006 Debentures are convertible at the holder’s option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of December 31, 2011, and the last business day immediately preceding the date specified by Penn West for redemption of the 6.5% 2006 Debentures, at a conversion price of $51.5534 per Trust Unit, being a conversion rate of approximately 19.3974 Trust Units for each $1,000 principal amount of 6.5% 2006 Debentures.

The 8% 2004 Debentures are convertible at the holder’s option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of August 31, 2009, and the last business day immediately preceding the date specified by Penn West for redemption of the 8% 2004 Debentures, at a conversion price of $30.2136 per Trust Unit, being a conversion rate of approximately 33.0977 Trust Units for each $1,000 principal amount of 8% 2004 Debentures.

The 6.5% 2005 Debentures are convertible at the holder’s option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of July 31, 2010 and the last business day immediately preceding the date specified by Penn West for redemption of the 6.5% 2005 Debentures, at a conversion price of $36.8155 per Trust Unit, being a conversion rate of approximately 27.1625 Trust Units for each $1,000 principal amount of 6.5% 2005 Debentures.

The 9.4% Debentures are convertible at the holder’s option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of July 31, 2008 and the last business day immediately preceding the date specified by Penn West for redemption of the 9.4% Debentures, at a conversion price of $31.1068 per Trust Unit, being a conversion rate of approximately 32.1473 Trust Units for each $1,000 principal amount of 9.4% Debentures.

The 7.2% Debentures are convertible at the holder's option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of May 31, 2011 and the last business day immediately preceding the date specified by Penn West for redemption of the 7.2% Debentures, at a conversion price of $75.00 per Trust Unit, being a conversion rate of approximately 13.3333 Trust Units for each $1,000 principal amount of 7.2% Debentures.

The 8% 2005 Debentures are convertible at the holder's option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of June 30, 2010 and the last business day immediately preceding the date specified by Penn West for redemption of the 8% 2005 Debentures, at a conversion price of $82.14 per Trust Unit, being a conversion rate of approximately 12.1743 Trust Units for each $1,000 principal amount of 8% 2005 Debentures.

Redemption and Purchase

The 6.5% 2006 Debentures are not redeemable on or before December 31, 2009. After December 31, 2009 and prior to maturity, the 6.5% 2006 Debentures may be redeemed in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days prior notice, at a redemption price of $1,050 per 6.5% 2006 Debenture after December 31, 2009 and on or before December 31, 2010 and at a redemption price of $1,025 per 6.5% 2006 Debenture after

December 31, 2010 and before maturity (each a "**6.5% 2006 Redemption Price**") in each case, plus accrued and unpaid interest thereon, if any.

The 8% 2004 Debentures may be redeemed in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 40 days prior notice, at a redemption price of $1,050 per 8% 2004 Debenture on or before August 31, 2008 and at a redemption price of $1,025 per 8% 2004 Debenture after August 31, 2008 and before maturity (each an "**8% 2004 Redemption Price**"), in each case, plus accrued and unpaid interest thereon, if any.

The 6.5% 2005 Debentures are not redeemable on or before July 31, 2008. The Trust may, on not more than 60 days and not less than 30 days prior notice, redeem the 6.5% 2005 Debentures at a redemption price of $1,050 per 6.5% 2005 Debenture after July 31, 2008, and on or before July 31, 2009, and at a price of $1,025 per 6.5% 2005 Debenture after July 31, 2009 and before July 31, 2010 (each a "**6.5% 2005 Redemption Price**"), plus accrued and unpaid interest thereon, if any.

The Trust may, on not more than 60 days and not less than 30 days prior notice, redeem the 9.4% Debentures at a redemption price of $1,025 per 9.4% Debenture before July 31, 2008 (each a "**9.4% Redemption Price**"), plus accrued and unpaid interest thereon, if any.

The 7.2% Debentures are not redeemable on or before May 31, 2009. The Trust may, on not more than 60 days and not less than 30 days prior notice, redeem the 7.2% Debentures at a redemption price of $1,050 per 7.2% Debenture after May 31, 2009 and on or before May 31, 2010, and a price of $1,025 per 7.2% Debenture after May 31, 2010 and before May 31, 2011 (each a "**7.2% Redemption Price**"), plus accrued and unpaid interest thereon, if any.

The 8% 2005 Debentures are not redeemable on or before June 30, 2008. After June 30, 2008 and prior to maturity, debenture holders may cause the Trust to redeem the 8% 2005 Debentures in whole or in part from time to time on not more than 60 days and not less than 30 days prior notice, at a redemption price of $1,050 per 8% 2005 Debenture after June 30, 2008 and before July 1, 2009, and a redemption price of $1,025 per 8% 2005 Debenture on or after July 1, 2009 and before maturity (each an "**8% 2005 Redemption Price**"), in each case, plus accrued and unpaid interest thereon, if any.

The Trust has the right to purchase Convertible Debentures in the market, by tender or by private contract.

Payment upon Redemption or Maturity

On redemption or at maturity, the Trust will repay the indebtedness represented by the Convertible Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the aggregate applicable redemption price of the outstanding Convertible Debentures which are to be redeemed or the principal amount of the outstanding Convertible Debentures which have matured together with accrued and unpaid interest thereon up to but excluding the date of redemption or maturity, as applicable. The Trust may, at its option, and subject to applicable regulatory approval, elect to satisfy its obligation to pay the applicable redemption price of the Convertible Debentures which are to be redeemed or the principal amount of the Convertible Debentures which have matured, as the case may be, by issuing Trust Units to the holders of the Convertible Debentures. Any accrued and unpaid interest thereon will be paid in cash. The number of Trust Units to be issued will be determined by dividing the aggregate applicable redemption price of the outstanding Convertible Debentures which are to be redeemed or the principal amount of the outstanding Convertible Debentures which have matured, as the case may be, by 95 percent of the Current Market Price of the Trust Units on the date fixed for redemption or the maturity date, as the case may be. The term "**Current Market Price**" is defined in the Convertible Debenture indentures to mean the weighted average trading price of the Trust Units on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date fixed for redemption or the maturity date, as the case may be.

Subordination

The payment of the principal of, and interest on, the Convertible Debentures is subordinated in right of payment, as set forth in the Debenture Indentures, to the prior payment in full of all Senior Indebtedness of the Trust. "**Senior Indebtedness**" of the Trust is defined in the Debenture Indentures as the principal of and premium, if any, and interest on and other amounts in respect of all indebtedness of the Trust (whether outstanding as at the date of the Debenture Indentures or thereafter incurred) which includes any indebtedness to trade creditors, other than indebtedness evidenced by the Convertible Debentures and all other existing and future debentures or other instruments of the Trust which, by the terms of the instrument creating or

evidencing the indebtedness, is expressed to be *pari passu* with, or subordinate in right of payment to, the Convertible Debentures.

The Debenture Indentures provide that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to the Trust, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of the Trust, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of the Trust, then those holders of Senior Indebtedness, including any indebtedness to trade creditors, will receive payment in full before the holders of Convertible Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Convertible Debentures or any unpaid interest accrued thereon. The Debenture Indentures also provide that the Trust will not make any payment, and the holders of the Convertible Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Convertible Debentures (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Convertible Debentures or (b) at any time when an event of default has occurred under the Senior Indebtedness and is continuing and the notice of such event of default has been given by or on behalf of the holders of Senior Indebtedness to the Trust, unless the Senior Indebtedness has been repaid in full.

The Convertible Debentures are effectively subordinate to claims of creditors of the Trust's Subsidiaries except to the extent the Trust is a creditor of such Subsidiaries ranking at least *pari passu* with such other creditors. Specifically, the Convertible Debentures are subordinated in right of payment to the prior payment in full of all indebtedness under the Trust's credit facilities and to the prior payment in full of PWPL's US$475 million principal amount of notes.

Priority over Trust Distributions

The Debenture Indentures provide that certain expenses of the Trust must be deducted in calculating the amount to be distributed to the Unitholders. Accordingly, the funds required to satisfy the interest payable on the Convertible Debentures, as well as the amount payable upon redemption or maturity of the Convertible Debentures or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be payable as distributions to Unitholders.

Change of Control of the Trust

Within 30 days following the occurrence of a change of control of the Trust involving the acquisition of voting control or direction over 66 $^{2}/_{3}$ percent or more of the Trust Units (a "**Change of Control**"), the Trust is required to make an offer in writing to purchase all of the Convertible Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 101 percent of the principal amount thereof plus accrued and unpaid interest (the "**Debenture Offer Price**").

If 90 percent or more of the aggregate principal amount of any series of Convertible Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Trust pursuant to the applicable Debenture Offer, the Trust will have the right and obligation to redeem all the remaining Convertible Debentures of that series, at the applicable Debenture Offer Price.

Interest Payment Option

The Trust may elect, from time to time, to satisfy its obligation to pay all or any part of the interest on the 6.5% 2006 Debentures, the 8% 2004 Debentures, the 6.5% 2005 Debentures and the 9.4% Debentures (but, for greater certainty, not the 7.2% Debentures or the 8% 2005 Debentures) (the "**Interest Obligation**"), on the date it is payable under the applicable Debenture Indenture (an "**Interest Payment Date**"), by delivering sufficient Trust Units to the Debenture Trustee to satisfy all or the part, as the case may be, of the Interest Obligation in accordance with the applicable Debenture Indenture (the "**Unit Interest Payment Election**"). The Debenture Indentures provide that, upon such election, the Debenture Trustee shall: (a) accept delivery from the Trust of Trust Units; (b) accept bids with respect to, and consummate sales of, such Trust Units, each as the Trust shall direct in its absolute discretion; (c) invest the proceeds of such sales in short-term permitted government securities (as defined in the applicable Debenture Indenture) which mature prior to the applicable Interest Payment Date, and use the proceeds received from such permitted government securities, together with any proceeds from

the sale of Trust Units not invested as aforesaid, to satisfy the Interest Obligation; and (d) perform any other action necessarily incidental thereto.

If a Unit Interest Payment Election is made, the sole right of a holder of Convertible Debentures in respect of interest will be to receive cash from the Debenture Trustee out of the proceeds of the sale of Trust Units (plus any amount received by the Debenture Trustee from the Trust attributable to any fractional Trust Units) in full satisfaction of the Interest Obligation, and the holder of such Convertible Debentures will have no further recourse to the Trust in respect of the Interest Obligation.

Events of Default

The Debenture Indentures provide that an event of default (" **Event of Default**") in respect of the Convertible Debentures will occur if any one or more of the following described events has occurred and is continuing with respect of the Convertible Debentures: (a) failure for 10 days to pay interest on the Convertible Debentures when due; (b) failure to pay principal or premium, if any, on the Convertible Debentures when due, whether at maturity, upon redemption, by declaration or otherwise; (c) certain events of bankruptcy, insolvency or reorganization of the Trust under bankruptcy or insolvency laws; or (d) default in the observance or performance of any material covenant or condition of the Debenture Indentures and continuance of such default for a period of 30 days after notice in writing has been given by the Debenture Trustee to the Trust

specifying such default and requiring the Trust to rectify the same. If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall upon request of holders of not less than 25 percent of the principal amount of the applicable Convertible Debentures then outstanding, declare the principal of and interest on all outstanding such Convertible Debentures to be immediately due and payable. In certain cases, the holders of more than 50 percent of the principal amount of the applicable Convertible Debentures then outstanding may, on behalf of the holders of all such Convertible Debentures, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Offers for Debentures

The Debenture Indentures contain provisions to the effect that if an offer is made for any series of Convertible Debentures, which is a take-over bid for such series of Convertible Debentures within the meaning of the *Securities Act* (Alberta) and not less than 90 percent of such Convertible Debentures (other than Convertible Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Convertible Debentures held by the holders of such series of Convertible Debentures who did not accept the offer on the terms offered by the offeror.

Modification

The rights of the holders of the Convertible Debentures may be modified in accordance with the terms of the Debenture Indentures. For that purpose, among others, the Debenture Indentures contain certain provisions which will make binding on all Convertible Debenture holders' resolutions passed at meetings of the holders of Convertible Debentures by votes cast thereat by holders of not less than 66$^{2}/_{3}$ percent of the principal amount of the Convertible Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66$^{2}/_{3}$ percent of the principal amount of the Convertible Debentures then outstanding. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Convertible Debentures of each particularly affected series.

Limitation on Issuance of Additional Convertible Debentures

The Debenture Indentures provide that the Trust shall not issue additional Convertible Debentures of equal ranking if the principal amount of all issued and outstanding Convertible Debenture of the Trust exceeds 25 percent of the Total Market Capitalization of the Trust immediately after the issuance of such additional Convertible Debenture. "**Total Market Capitalization**" is defined in the Debenture Indentures as the total principal amount of all issued and outstanding Convertible Debentures of the Trust which are convertible at the option of the holder into Trust Units plus the amount obtained by multiplying the number of issued and outstanding Trust Units by the Current Market Price of the Trust Units on the relevant date.

Limitation on Non-Resident Ownership

The Debenture Trustee may require declarations as to the jurisdictions in which beneficial owners of Convertible Debentures are resident. If the Debenture Trustee becomes aware as a result of requiring such declarations as to beneficial ownership, that the beneficial owners of 49 percent of the Trust Units then outstanding (40 percent in the case of the 6.5% 2006 Debentures and not more than half in the case of the 8% 2005 Debentures and the 7.2% Debentures), on a fully diluted basis, are, or may be, Non-Residents or that such a situation is imminent, the Debenture Trustee may make a public announcement thereof and shall not register a transfer of Convertible Debentures to a person unless the person provides a declaration that the person is not a Non-Resident. If, notwithstanding the foregoing, the Debenture Trustee determines that a majority of the Trust Units are held by Non-Residents, the Debenture Trustee may send a notice to Non-Resident holders of Convertible Debentures, chosen in inverse order to the order of acquisition or registration of the Convertible Debentures or in such manner as the Debenture Trustee may consider equitable and practicable, requiring them to sell their Convertible Debentures or a portion thereof within a specified period of not less than 60 days. If the Convertible Debenture holders receiving such notice have not sold the specified number of Convertible Debentures or provided the Debenture Trustee with satisfactory evidence that they are not Non-Residents within such period, the Debenture Trustee may on behalf of such holder of Convertible Debentures, and, in the interim, shall suspend the rights attached to such Convertible Debentures. Upon such sale the affected holders shall cease to be holders of Convertible Debentures, and their rights shall be limited to receiving the net proceeds of sale upon surrender of such Convertible Debentures.

Book-Entry System for Convertible Debentures

The Convertible Debentures (other than the 8% 2005 Debentures) are issued in "book-entry only" form and must be purchased or transferred through a participant in the depository service of CDS & Co. The Convertible Debentures (other than the 8% 2005 Debentures) are evidenced by a single book-entry only certificate. Registration of interests in and transfers of the Convertible Debentures (other than the 8% 2005 Debentures) is made only through the depository service of CDS & Co.

The 8% 2005 Debentures are issued as fully registered debentures in certificated form and beneficial holders of 8% 2005 Debentures may receive definitive certificates representing their interest in 8% 2005 Debentures.

Ratings

Penn West has not asked for and received a stability rating, and it is not aware that it has received any other kind of rating, including a provisional rating, from one or more approved rating organizations for outstanding securities of Penn West, which rating or ratings continue in effect.

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.

PWPL presently administers us on behalf of the Trustee. PWPL, 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 PWPL to issue shares of PWPL 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 PWPL 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".

PWPL 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 for us to maintain our status as a mutual fund trust under the Tax Act, we must not be established or maintained primarily for the benefit of Non-Residents unless we satisfy the requirements of certain exceptions. The Trust Indenture provides that Penn West will use its best commercial efforts to maintain its status as a mutual fund trust under the Tax Act. Generally speaking, the Tax Act 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 (which is generally interpreted to mean that the majority of unitholders must not be Non-Residents), unless at the relevant time, "all or

substantially all" of the trust's property consists of property other than taxable Canadian property (the " **TCP Exception**"). We have determined that we currently meet 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. 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 PWPL 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 PWPL 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 Internal Notes issued by PWPL to the Trust.

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, PWPL has been delegated responsibility for substantially all of the management decisions of Penn West. The Unitholders are entitled to elect all of the members of the Board of Directors of PWPL 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 PWPL at all meetings in respect of matters relating to the election of the directors of PWPL, approving its financial statements and appointing auditors of PWPL who shall be the same as our auditors. Prior to us voting our common shares in PWPL 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 PWPL 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, PWPL and our other direct or indirect Subsidiaries 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 PWPL'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 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 PWPL. The current distribution policy targets the use of approximately 60 percent to 70 percent of funds 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 funds flow will fund all or a portion of Penn West'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 Penn West 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 TSX. 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.

The credit agreement governing Penn West's $4 billion syndicated credit facility and the note purchase agreement governing PWPL's US$475 million principal amount of notes both contain provisions which restrict the ability of PWPL to pay Penn West under the NPIs and interest on the Internal Notes and thereby may restrict distributions to Unitholders in the event of the occurrence of certain events of default. For further information regarding the credit agreement governing our syndicated credit facility, reference is made to note 5 of our consolidated financial statements for the year ended December 31, 2007. For further information regarding the note purchase agreement governing PWPL's notes, reference is made to note 5 of our consolidated financial statements for the year ended December 31, 2007. Note 5 of our consolidated financial statements for the year ended December 31, 2007 is incorporated by reference in this Annual Information Form. Our consolidated financial statements for the year ended December 31, 2007 are filed on SEDAR at www.sedar.com. For additional information, see "Risk Factors – Debt Service".

Directors and Executive Officers of PWPL

The following table sets forth the name, province/state and country of residence and positions and offices held for each of the directors and executive officers of PWPL as of February 29, 2008 following completion of the Canetic Acquisition, together with their principal occupations during the last five years. The directors of PWPL will hold office until the next annual meeting of Unitholders or until their respective successors have been duly elected or appointed.

Name, Province/State and Country of Residence	Positions and Offices Held	Principal Occupations during the Five Preceding Years
James E. Allard(1) Alberta, Canada	Director since 2006	Independent director and business advisor. Also, a member of the Alberta Securities Commission from 1999 to 2005.

Name, Province/State and Country of Residence	Positions and Offices Held	Principal Occupations during the Five Preceding Years
William E. Andrew Alberta, Canada	Chief Executive Officer Director since 1994	Chief Executive Officer of PWPL since January 11, 2008. Prior thereto, President and Chief Executive Officer of PWPL since May 2005. Prior thereto, President of PWPL.
Robert G. Brawn(3)(5) Alberta, Canada	Director since January 11, 2008	President of 738831 Alberta Ltd. (a private investment company) since 2003. Prior thereto, Chairman of Acclaim Energy Inc. ("**Acclaim**"), the administrator of Acclaim Energy Trust (a public oil and gas income trust), a predecessor of Canetic. Also, a corporate director of a number of companies, including a director of the administrator of Canetic from its inception in January 2006 until January 2008.
George H. Brookman(2)(4)(5) Alberta, Canada	Director since 2005	President and Chief Executive Officer of West Canadian Industries Group Inc. (a commercial digital printing and graphics company).
John A. Brussa Alberta, Canada	Chairman of the Board of Directors and director since 1995	Senior Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Daryl Gilbert(3)(5) Alberta, Canada	Director since January 11, 2008	President and Chief Executive Officer of GLJ Petroleum Consultants Ltd. (formerly Gilbert Laustsen Jung Associates Ltd.) (an engineering consulting firm) until 2005. Director of the administrator of Canetic from its inception in January 2006 until January 2008. Independent business consultant since 2005.
Jack C. Lee Alberta, Canada	Vice Chairman of the Board of Directors and director since January 11, 2008	Corporate director since October 2002, including Chairman of the Canetic Board of Directors from its inception in January 2006 until January 2008. Prior thereto, President and Chief Executive Officer of Acclaim.
Shirley A. McClellan(1)(4)(5) Alberta, Canada	Director since 2007	Independent businesswoman since 2007. Prior thereto, Deputy Premier of the Province of Alberta from 2001 to 2007 and Minister of Finance of the Province of Alberta from 2004 to 2007.
Thomas E. Phillips(3) Alberta, Canada	Director since 1995	President, Newhaven Investments Inc. (a private oil and gas company).
Frank Potter(1)(4) Ontario, Canada	Director since 2006	Chairman of Emerging Markets Advisors, Inc. (an investment consulting firm).
R. Gregory Rich(2)(4) Texas, United States	Director since January 11, 2008	Principal of Blackrock Energy Associates (an energy consulting and investment firm) and President and Chief Executive Officer of XPRONET Resources Inc. (a private oil and gas company). Also, a director of the administrator of Canetic from its inception in January 2006 until January 2008.
James C. Smith(1)(2)(3) Alberta, Canada	Director since 2005	Independent director and consultant to a number of public and private oil and gas companies.

Name, Province/State and Country of Residence	Positions and Offices Held	Principal Occupations during the Five Preceding Years

Murray Nunns Alberta, Canada	President and Chief Operating Officer	President and Chief Operating Officer of PWPL since February 8, 2008. Prior thereto, director of PWPL and Executive Chairman of Monterey Exploration Ltd., a private oil and gas company. Prior thereto, a variety of management positions at Rio Alto Exploration Ltd., a public oil and gas company.
Todd H. Takeyasu Alberta, Canada	Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer of PWPL since February 8, 2008. Prior thereto, Senior Vice President, Finance – Treasury of PWPL since January 11, 2008. Prior thereto, Senior Vice President and Chief Financial Officer of PWPL since 2006. Prior thereto, Vice President, Finance of PWPL since 2005. Prior thereto, Treasurer of PWPL.
David W. Middleton Alberta, Canada	Executive Vice President, Operations and Corporate Development	Executive Vice President, Operations and Corporate Development of PWPL since February 8, 2008. Prior thereto, Chief Operating Officer of PWPL since January 11, 2008. Prior thereto, Executive Vice President and Chief Operating Officer of PWPL since 2005. Prior thereto, Senior Vice President, Production of PWPL since 2003. Prior thereto, Vice President, Production of PWPL.
Mark P. Fitzgerald Alberta, Canada	Senior Vice President, Engineering	Senior Vice President, Engineering of PWPL since January 11, 2008. Prior thereto, Vice President, Operations of Canetic since January 2006. Prior thereto, Vice President, Operations of Acclaim since February 2005. Prior thereto, Vice President, Engineering of Acclaim (since 2004) and Manager, Western District of Acclaim (from 2003 to 2004). Prior thereto, worked in asset management, acquisitions and mergers for Dominion Energy Canada Ltd. (an oil and gas company).
Thane A.E. Jensen Alberta, Canada	Senior Vice President, Exploration and Development	Senior Vice President, Exploration and Development of PWPL since 2005. Prior thereto, Vice President, Engineering of PWPL since 2004. Prior thereto, Manager, Exploitation of PWPL.
Keith Luft Alberta, Canada	General Counsel and Senior Vice President, Stakeholder Relations	General Counsel and Senior Vice President, Stakeholder Relations of PWPL since February 8, 2008. Prior thereto, Senior Vice President, Stakeholder Relations of PWPL since January 11, 2008. Prior thereto, Vice President, Land and Legal of PWPL since 2006. Prior thereto, Senior Solicitor of Conoco Phillips Canada Ltd./Burlington Resources Canada Ltd. (an oil and gas company) since May 2004. Prior thereto, partner in Calgary based law firm.

Name, Province/State and Country of Residence	Positions and Offices Held	Principal Occupations during the Five Preceding Years
Eric J. Obreiter Alberta, Canada	Senior Vice President, Production	Senior Vice President, Production of PWPL since January 11, 2008. Prior thereto, Vice President, Production of PWPL since 2005. Prior thereto, Manager, Production Central of PWPL.
John Artym Alberta, Canada	Vice President, Health, Safety and Training	Vice President, Health, Safety and Training of PWPL since January 11, 2008. Prior thereto, Manager, Health, Safety and Training of PWPL since 2004. Prior thereto, various health and safety management positions held with PWPL, BJ Services Company and its predecessor Nowsco Well Service Ltd. (a private oil and gas services company).
Brett Frostad Alberta, Canada	Vice President, Exploration; Heavy Oil District	Vice President, Exploration; Heavy Oil District of PWPL since January 11, 2008. Prior thereto, Vice President, Exploration North of PWPL since 2007. Prior thereto, Team Manager, Swan Hills of PWPL since 2005. Prior thereto, District Geologist of PWPL since 2004. Prior thereto, Senior Geologist of PWPL since 2002.

Gregg Gegunde Alberta, Canada	Vice President, Development; Heavy Oil District	Vice President, Development; Heavy Oil District of PWPL since January 11, 2008. Prior thereto, Vice President, Development North of PWPL since June 2005. Prior thereto, Manager, Production Plains of PWPL.
Brian Keller Alberta, Canada	Vice President, Exploration; Light Oil District	Vice President, Exploration; Light Oil District of PWPL since January 11, 2008. Prior thereto, Vice President of Exploitation of Canetic since November 2006. Prior thereto, Director of Geology and Geophysics of Acclaim.
Lucas Law Alberta, Canada	Vice President, Acquisitions and Divestments	Vice President, Acquisitions and Divestments of PWPL since January 11, 2008. Prior thereto, Vice President, Asset Management of PWPL since 2006. Prior thereto, Manager, Corporate Development since 2005. Prior thereto, Supervisor, Exploitation since 2004. Prior thereto, Team Leader, Petrovera Resources.
Doug Marjerrison Alberta, Canada	Vice President, Development; Gas District	Vice President, Development; Gas District of PWPL since January 11, 2008. Prior thereto, Manager, Border Plains/Southern Business Unit of Canetic since July 2007. Prior thereto, Manager, Southern Business Unit of Canetic since September 2006. Prior thereto, Exploitation Engineer with Canetic.
Bill Morgan Alberta, Canada	Vice President, Joint Venture and Midstream Services	Vice President, Joint Venture and Midstream Services of PWPL since January 11, 2008. Prior thereto, Manager, Operations Plains/South of PWPL since 2006. Prior thereto, Manager, Joint Venture of PWPL.

Name, Province/State and Country of Residence	Positions and Offices Held	Principal Occupations during the Five Preceding Years
Keith Rockley Alberta, Canada	Vice President, Human Resources and Corporate Administration	Vice President, Human Resources and Corporate Administration of PWPL since January 11, 2008. Prior thereto, Vice President, Human Resources and Corporate Administration of Canetic since January 2006. Prior thereto, Vice-President Human Resources and Corporate Administration of Acclaim since November 2005. Prior thereto, President of Human Resource Solutions Inc. (a private consulting business) from April 2005 to October 2005. Prior thereto, Manager, Human Resources, Husky Energy Inc. (an oil and gas company).
Don Robson Alberta, Canada	Vice President, Land	Vice President, Land of PWPL since January 11, 2008. Prior thereto, Vice President, Land of Canetic since 2006. Prior thereto, Vice President, Land of Acclaim since 2005. Prior thereto, Manager Land Negotiations and Director of Land of Acclaim since 2004. Prior thereto, Land Manager at Energy North Inc. (an oil and gas company).
Dave Sterna Alberta, Canada	Vice President, Marketing	Vice President, Marketing of PWPL since January 11, 2008. Prior thereto, Vice President, Corporate Planning and Marketing of Canetic since January 2006. Prior thereto, Vice President, Corporate Planning and Marketing of Acclaim since November 2005. Prior thereto, Director of Marketing for Acclaim since September 2004. Prior thereto, Director of Marketing for Calpine Canada (an energy company).
Kristian Tange Alberta, Canada	Vice President, Corporate Development and Planning	Vice President, Corporate Development and Planning of PWPL since January 11, 2008. Prior thereto, Vice President, Business Development of PWPL since 2005. Prior thereto, Manager, Marketing of PWPL since 2003. Prior thereto, Manager, Natural Gas Marketing of PWPL.
Anne Thomson Alberta, Canada	Vice President, Exploration; Gas District	Vice President, Exploration; Gas District of PWPL since January 11, 2008. Prior thereto, Vice President, Exploration South of PWPL since June 2005. Prior thereto, Manager, Exploration of PWPL since 2003. Prior thereto, District Geologist of PWPL.

Name, Province/State and Country of Residence	Positions and Offices Held	Principal Occupations during the Five Preceding Years
Donald Wood Alberta, Canada	Vice President, Development; Light Oil District	Vice President, Development; Light Oil District of PWPL since January 11, 2008. Prior thereto, Vice President, Development South of PWPL since September 2007. Prior thereto, President and Chief Executive Officer of C1 Energy Ltd. (a public oil and gas company) since January 2007. Prior thereto, Executive Vice President and Chief Operating Officer of C1 Energy Ltd. since June 2006. Prior thereto, President and Chief Executive Officer of High Energy Resources Limited (a private oil and gas company) since February 2005. Prior thereto, President and Chief Executive Officer of Kensington Energy Ltd. (a public oil and gas company).
Sherry Wendt Alberta, Canada	Corporate Secretary	Corporate Secretary of PWPL since February 8, 2008. Prior thereto, Corporate Counsel at PWPL since 2007. Prior thereto, practiced with the law firm Bennett Jones LLP.

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.

As at March 26, 2008, the directors and executive officers of PWPL, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,345,893 Trust Units or approximately 0.4 percent of the issued and outstanding Trust Units.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as otherwise disclosed herein, no director or executive officer of PWPL (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, Chief Executive Officer or Chief Financial Officer of any company (including PWPL), that:

(a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, Chief Executive Officer or Chief Financial Officer; or

(b) was subject to an Order that was issued after the director or executive officer ceased to be a director, Chief Executive Officer or Chief Financial Officer and which resulted from an event that occurred while that person was acting in the capacity as director, Chief Executive Officer or Chief Financial Officer.

Daryl Gilbert is a director of Globel Direct, Inc., which was subject to a cease trade order issued by the British Columbia Securities Commission on November 20, 2002 and the Alberta Securities Commission on November 22, 2002 for delay in filing financial statements. The required financial statements were filed and the cease trade orders were revoked effective December 23, 2002. The company sought and received protection under CCAA in June 2007, and after a failed restructuring effort, a receiver was appointed by one of the company's lenders in December 2007.

Except as otherwise disclosed herein, no director or executive officer of PWPL (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Penn West to affect materially the control of Penn West:

(a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including PWPL) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become 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 the director, executive officer or shareholder.

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. (subsequently renamed Rider Resources Ltd.), both of which were listed on the TSX.

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 TSX. 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.

No director or executive officer of PWPL (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Penn West to affect materially the control of Penn West, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

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 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 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 Penn West.

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 Penn West. Passive investments in public or private entities of less than one per cent of the outstanding shares will not be viewed as "competing" with Penn West. No executive officer or employee of PWPL 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 PWPL 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 Penn West, the Board of Directors will take such actions

as are reasonably required to resolve such matters with a view to the best interests of Penn West. Such actions, without limitation, may include excluding such directors, officers or employees from certain information or activities of Penn West.

The ABCA 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. See "Risk Factors – Potential Conflicts of Interest".

As of the date hereof, Penn West is not aware of any existing or potential material conflicts of interest between Penn West or a Subsidiary of Penn West and any director or officer of Penn West or of any Subsidiary of Penn West, including PWPL.

Promoters

No person or company has been, within the two most recently completed financial years or during the current financial year, a "promoter" (as defined in the *Securities Act* (Ontario)) of Penn West or of a Subsidiary of Penn West.

AUDIT COMMITTEE DISCLOSURES

National Instrument 52-110 ("**NI 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.

Composition of the Audit Committee and Relevant Education and Experience

The members of the Audit Committee are James C. Smith, chairman, and James E. Allard, Shirley A. McClellan and Frank Potter, each of whom is independent and financially literate within the meaning of NI 52-110. The following comprises a brief summary of each member's education and experience that is relevant to the performance of his responsibilities as an Audit Committee member.

James C. Smith (Chairman)

Mr. Smith is a Chartered Accountant with over 35 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 TSX and completed several major debt and equity financing transactions. Mr. Smith is currently a director of TG World Equity Corp., 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 eight 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.

Frank Potter

Mr. Potter attended Royal Military College of Science, and is a Fellow of the Institute of Canadian Bankers. Mr. Potter has been the Chairman since 1995 of Emerging Markets Advisors, Inc., a Toronto-based consultancy that assists corporations in

making and managing direct investments internationally. Prior thereto, Mr. Potter was executive director of The World Bank Group in Washington, and was subsequently senior advisor at the federal Department of Finance. Mr. Potter is a director of a number of public and private corporations and public service organizations.

Shirley A. McClellan

Mrs. McClellan brings to Penn West the experience gained over 20 years of distinguished service to the Province of Alberta. Her career history includes the offices of Deputy Premier of Alberta from 2001 to 2007, Minister of Finance of Alberta from 2004 to 2007 and Chair of the Treasury Board and Vice-Chair of the Agenda and Priorities Committee of the Alberta Assembly. Mrs. McClellan has served a total of six terms as a Member of the Alberta Legislative Assembly representing the constituency of Drumheller-Stettler. Over this time period, she has held numerous other portfolios, including Minister of Agriculture, Food and Rural Development, Minister of International and Intergovernmental Relations, Minister of Community Development, and Minister of Health. Mrs. McClellan actively serves her community and is particularly passionate about enhancing further education in rural areas. She is a former director of the Alberta Association of Continuing Education and the Canadian Association for Continuing Education.

Pre-Approval Policies and Procedures for Non-Audit Services

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.

External Auditor Service Fees

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 in each of the last two fiscal years for audit services, including Sarbanes – Oxley compliance related services, were:

2007	-	$	1,045,000
2006	-	$	610,000

Audit Related Fees

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

2007	-	$	120,000

2006	-	$	105,000

The services comprising the fees disclosed under this category include French translation services.

Tax Fees

The aggregate fees billed in each of the last two fiscal years by our external auditor for professional services for tax compliance, tax advice and tax planning were:

2007	-	$	7,914
2006	-	$	18,341

The services comprising the fees disclosed under this category include the following: assistance and advice in relation to the communication of the taxability of distributions to Unitholders and the review of corporate income tax returns.

All Other Fees

The aggregate fees billed in each of the last two fiscal years by our external auditor for products and services not included under the headings Audit Fees, Audit Related Fees and Tax Fees were:

2007	-	$	NIL
2006	-	$	NIL

Reliance on Exemptions

At no time since the commencement of Penn West's most recently completed financial year has Penn West relied on any of the exemptions contained in Sections 2.4, 3.2, 3.4 or 3.5 of NI 52-110, or an exemption from NI 52-110, in whole or in part, granted under Part 8 thereof. In addition, at no time since the commencement of Penn West's most recently completed financial year has Penn West relied upon the exemptions in Subsection 3.3(2) or Section 3.6 of NI 52-110. Furthermore, at no time since the commencement of Penn West's most recently completed financial year has Penn West relied upon Section 3.8 of NI 52-110.

Audit Committee Oversight

At no time since the commencement of Penn West's most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Board of Directors of PWPL.

DISTRIBUTIONS TO UNITHOLDERS

Since our formation as a trust, monthly cash distributions have been declared in the following amounts, each amount being paid in the following month:

For the Month Ended	Distributions per Unit			
	2008	2007	2006	2005
January	$ 0.34	$ 0.34	$ 0.31	N/A
February	0.34	0.34	0.34	N/A
March	0.34	0.34	0.34	N/A
April	—	0.34	0.34	N/A
May	—	0.34	0.34	N/A
June	—	0.34	0.34	$ 0.26
July	—	0.34	0.34	0.26
August	—	0.34	0.34	0.26
September	—	0.34	0.34	0.26
October	—	0.34	0.34	0.31
November	—	0.34	0.34	0.31
December	—	0.34	0.34	0.31
Total	$ 1.02	$ 4.08	$ 4.05	$ 1.97

For Canadian and United States income tax purposes, cash distributions paid to Unitholders in 2005, 2006 and 2007 were 100 percent taxable as other income.

MARKET FOR SECURITIES

The Trust Units are listed and traded on the TSX under the symbol PWT.UN and on the NYSE under the symbol PWE. The following tables set forth certain trading information for our Trust Units in 2007.

	TSX		
Period	Unit price ($) High	Unit price ($) Low	Volume
January	35.80	32.32	17,597,965
February	36.88	34.09	11,851,438
March	36.05	32.48	14,490,763
April	34.63	33.11	11,900,009
May	38.33	33.12	15,145,415
June	38.15	33.50	15,215,785
July	36.09	32.57	11,523,717
August	33.48	28.48	14,511,853
September	31.46	28.66	12,486,728
October	31.83	29.89	15,984,431
November	30.27	25.90	20,602,889
December	27.31	25.25	19,265,161

	NYSE		
Period	Unit price ($ US) High	Unit price ($ US) Low	Volume
January	30.50	27.50	18,695,800
February	31.81	29.08	13,746,969
March	31.11	27.61	18,183,252
April	30.58	29.18	11,484,019
May	36.30	29.93	20,095,788
June	36.05	31.25	14,163,452
July	34.58	30.71	14,011,508
August	31.50	26.47	20,417,456
September	31.42	28.42	15,805,123
October	33.06	30.57	17,971,612
November	32.17	26.06	28,651,264
December	27.10	25.61	27,558,864

Penn West assumed the 7.2% Debentures and the 8% 2005 Debentures from Vault on January 10, 2008 in connection with the Vault Acquisition. The 7.2% Debentures and the 8% 2005 Debentures began trading on the TSX as securities of Penn West on January 15, 2008 under the symbols “PWT.DB.E” and “PWT.DB.C”, respectively.

Penn West assumed the 6.5% 2005 Debentures, the 6.5% 2006 Debentures, the 8% 2004 Debentures and the 9.4% Debentures from Canetic on January 11, 2008 in connection with the completion of the Canetic Acquisition. The 6.5% 2005 Debentures, the 6.5% 2006 Debentures, the 8% 2004 Debentures and the 9.4% Debentures began trading on the TSX as securities of Penn West on January 16, 2008 under the symbols “PWT.DB.D”, “PWT.DB.F”, “PWT.DB.B” and “PWT.DB.A”, respectively.

Penn West does not have any classes of securities that are outstanding but that are not listed or quoted on a market place. In addition, to Penn West’s knowledge, no securities of Penn West are held in escrow, are subject to a pooling agreement, or are subject to a contractual restriction on transfer (except in respect of pledges made to lenders).

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, geo-political events 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 (other than its constituent by-products of propane, butane and ethane) 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, insufficient firm pipeline capacity can from time to time impede our ability to produce and market our oil and natural gas production.

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 that 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 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 funds 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 October 2007 Economic Statement and Notice of Ways and Means Motion and 2006 Federal Budget, the federal corporate income tax rate will decrease to 15 percent in five steps: 19.5 percent on January 1, 2008; 19 percent on January 1, 2009; 18 percent on January 1, 2010; 16.5 percent on January 1, 2011; and 15 percent on January 1, 2012.

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 as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it 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, 2009, 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 and a new program was to be introduced. In addition, the Alberta Royalty Tax Credit Program ("**ARTC**") was 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 new program 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 that 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 was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime, which is scheduled to be effective on January 1, 2009. The proposal includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity. The proposal also introduces the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources, which is consistent with the government's objective of maximizing the recovery of known gas resources, while increasing royalty revenues. The policy's objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government so that they may be made available for resale. It appears that leaseholders will receive a grace period before the shallow zones revert to the government, although the details of the policy have yet to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "Risk Factors – New Alberta Royalty Regime".

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 than 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 (the "**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.

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 is 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 federal government 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 is limited in its carry forward to five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the *Oil and Gas Conservation Act* and the *Oil and Gas Conservation Regulations* , 1985. The program includes a security deposit, which has two purposes: (i) preventing the individual with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan property. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

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 subject to environmental regulations under a variety of provincial and federal legislation. Environmental regulations impose, among other things, restrictions, prohibitions, 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, including substances produced in association with certain oil and gas industry operations. 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 and a breach of such requirements could result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties and facility closures.

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol (“ **Protocol**”). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 “business as usual” levels between 2008 and 2012. Given revised estimates of Canada’s normal emissions levels, this target translates into an approximate 40 percent gross reduction in Canada’s current emissions. It is uncertain, based on the Updated Action Plan announced by the federal government (see below), whether the Protocol target of 6 percent below 1990 emission levels will be enforced in Canada. Bill C-288, which was intended to ensure that Canada meets its global climate change obligations under the Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the federal government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the “**Action Plan**”) also known as ecoACTION, which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends, among other things: (i) incorporating carbon capture and storage into Canada’s clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released “Turning the Corner – Taking Action to Fight

Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the federal government's plan to reduce greenhouse gas emissions by 20 percent by 2020 and by 60 percent to 70 percent by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emissions and establish a market price for carbon. There are mandatory reductions of 18 percent from the 2006 baseline starting in 2010 and an additional 2 percent per year in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oils sands production, petroleum refining, natural gas pipelines and upstream oil and gas, the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a three-year grace period during which no emissions intensity targets will apply. Targets will begin to

apply on the fourth year of commercial operation and the baseline will be the third-year's emissions intensity, with a 2 percent continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25 percent increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific: oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO2 equivalent per upstream oil and gas facilities; and (iii) 10,000 boe/d per company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO2 equivalent per year per facility. See "Industry Conditions – Environmental Regulation – Alberta" below.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions; offset credits; clean development credits; and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund, to which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010 to 2012 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of gross domestic product growth. Contribution limits will correspondingly decline from 70 percent in 2010 to nil in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Protocol. The purchase of such emissions reduction credits will be restricted to 10 percent of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 metric tons worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

It is currently intended that the proposed greenhouse gas regulations will be published later in 2008, and that the regulations will be finalized in 2009 prior to coming into force on January 1, 2010.

Alberta

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. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities

that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO2 from other emissions supporting carbon capture and storage.

British Columbia

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. 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. For this purpose, on December 18, 2007, proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry, the objective is to achieve clean energy through conservation and energy efficient practices, while 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 Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment 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) the new 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. In furtherance of these initiatives, on February 19, 2008 the provincial government announced that starting on July 1, 2008, provided the legislation is approved, a revenue-neutral carbon tax will be applied to all fossil fuels used in the province. The tax would be phased in, and the initial rate would be based on CO2 equivalent of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, followed by $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the government would receive otherwise.

Penn West and the Environment

As the federal and provincial programs relating to the regulation of the emission of greenhouse gases and other air pollutants are under development, we are currently unable to predict the total impact of the potential regulations upon our business. Therefore, it is possible that we could face increases in operating costs in order to comply with emissions legislation. However, we, in cooperation with the Canadian Association of Petroleum Producers, will continue to work with 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 Regulation".

We fully understand our responsibilities of reducing the environmental impacts from our operations 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 our operations, and to involving stakeholders throughout the exploration, development, production and abandonment process. Our environmental programs encompass resource conservation, stakeholder communication, CO_2 sequestration and site abandonment/reclamation. Our environmental programs are monitored to ensure that they comply with all government environmental regulations and with our own environmental policies. The results of these programs are reviewed with our management and operations personnel.

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 economic 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. We pursue 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 2008, 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" CO_2 in hydrocarbon reservoirs.

During 2007, we continued our pilot-scale CO_2 injection program at Pembina, where the injection of CO_2 commenced in February 2005. To date, in excess of 1.6 Bcf of liquid CO_2 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 CO_2. Also in 2007, we continued to participate in studies to develop a cost effective system to source large volumes of CO_2 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".

We are committed to meeting our responsibilities to protect the environment wherever we operate and 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. We will be taking such steps as required to ensure continued compliance with applicable environmental legislation in each jurisdiction in which we operate. We believe that we are currently 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.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of Penn West and the Operating Entities. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form. Unitholders and potential Unitholders should consider carefully the information contained

herein and, in particular, the following risk factors.

Being a limited purpose trust makes us largely dependent upon the operations and assets of the Operating Entities. If the oil and natural gas reserves associated with the Operating Entities' resource properties are not supplemented through additional development activities or the acquisition of oil and natural gas properties, the ability of the Operating Entities to continue to generate funds flow from operations for distribution to Unitholders may become adversely affected.

We are entirely dependent upon the operations and assets of the Operating Entities through our ownership, directly and indirectly, of securities of the Operating Entities, including the common shares of PWPL, the Internal Notes and the NPIs. Accordingly, our ability to pay cash distributions to Unitholders are dependent upon the ability of the Operating Entities to meet their interest, principal, dividend and other distribution obligations on the securities of the Operating Entities and the NPIs. The Operating Entities' income is received from the production of oil and natural gas from the Operating Entities' resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally.

Volatility of Oil and Natural Gas Prices

Our operational results and the financial condition of our Operating Entities and therefore the amounts paid to us and ultimately distributed to our Unitholders 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 funds flow from operations, financial condition and therefore on our financial position and the cash available to be distributed to our 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 increase. In addition, commodity hedging activities could expose us to cash and income losses. To the extent that we engage in risk management activities, there are credit risks associated with counterparties with which we contract.

Geo-Political Risks

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

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of a terrorist attack it could have a material adverse effect on us. We do not currently have insurance to protect against the risk of terrorism.

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 funds flow to Unitholders, we will not be reinvesting funds flow in the same manner as some other corporate industry participants and will only conduct limited exploratory activities as one of our main objectives is to maximize long-term distributions. Accordingly, absent equity capital injections or increased debt levels, our 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 funds 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 funds flow to finance capital expenditures or property acquisitions, the level of funds 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.

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/US dollar exchange rate which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar and has at times traded above par against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted Penn West's Operating Entities production revenues. Any further material increases in the value of the Canadian dollar relative to the United States dollar would exacerbate this negative impact. This 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 (whether as a result of a further deterioration of the credit market or otherwise) could result in a significant increase in the amount we pay to service debt, resulting in a decrease in distributions to Unitholders, which would negatively impact the market price of the Trust Units.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and resources and funds flows to be derived therefrom, including many factors beyond our control. The reserve and associated funds flow information set forth in this Annual Information Form represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net funds 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 and resources are attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves or estimates of resources 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 and resource 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 and Sproule have used forecast price and cost estimates in calculating reserve quantities included in this Annual Information Form. Actual future net funds 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 funds flows derived from reserves will vary from the reserve estimates contained in the engineering reports summarized in this Annual Information Form, and such variations could be material. The engineering reports summarized in this Annual Information Form are based in part on the assumption that certain activities will be undertaken by us in future years and the further assumption that such activities will be successful. The reserves and estimated funds 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 are not undertaken or, if undertaken, do not achieve the level of success assumed in the engineering reports summarized in this Annual Information Form.

Environmental Regulation

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, pipelines and associated 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 legal 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 Kyoto Protocol and the Government of Canada's Clean Air Act of 2006. The Clean Air Act proposes to reduce greenhouse gas emissions and other contaminants, 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 us. Provincial emission reduction requirements, such as those contained in Alberta's *Climate Change and Emissions Management Act*, 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".

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on us and our operations and financial condition.

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 acquisition of properties with longer life reserves and properties with exploitation and development opportunities. The SIFT Tax imposed by the Government of Canada is expected by management to make our Trust Units less attractive as consideration for acquisitions. See "Risk Factors – 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.

Reliance on Management

Unitholders will be dependent on the management of PWPL in respect of the administration and management of all matters relating to our operations. Investors who are not willing to rely on the management of PWPL should not invest in the Trust Units or the Convertible Debentures.

Federal Tax Changes

On October 31, 2006, the Federal Minister of Finance proposed to deny the deduction of distributions at the trust level and subject any income of certain publicly traded mutual fund trusts to tax at rates comparable to the combined federal and provincial corporate tax and to treat such distributions as taxable dividends to the unitholders (the "**SIFT Tax**"). On December 21, 2006, the Federal Minister of Finance released draft legislation to implement the SIFT Tax 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 our Unitholders and will be subject to tax at the corporate rates at the trust level. On June 22, 2007, the legislation received Royal assent. The implementation of the SIFT Tax is 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 of PWPL believes that the SIFT Tax has reduced, and may further 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 of PWPL believes that the SIFT Tax: (a) has substantially eliminated any competitive advantage that Penn West and other Canadian energy trusts have enjoyed relative to their corporate peers in raising capital in a tax-efficient manner; and (b) may place Penn West and other Canadian energy trusts at a competitive disadvantage relative to certain of their industry competitors, including US master limited partnerships, which will continue to not be subject to entity level taxation. The SIFT Tax may also make the Trust Units less attractive as consideration for acquisitions in the future. As a result, it may become more difficult for us to compete effectively for acquisition opportunities.

Further, the SIFT Tax provides that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" would result in the transition period being terminated with the loss of the benefit to us of that transitional

period. As a result, the adverse tax consequences resulting from the SIFT Tax 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:

- 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);
- 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
- 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.

Penn West's and Canetic's combined market capitalization as of the close of trading on October 31, 2006, having regard only to the issued and outstanding publicly-traded Trust Units and Canetic trust units at such date, was approximately $15 billion, which means the combined "safe harbour" equity growth amount for the period ending December 31, 2007 is approximately $6 billion, and for each of calendar year 2008, 2009 and 2010 is an additional approximately $3 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 may adversely affect the cost of raising capital and our ability to undertake more significant acquisitions.

Currently, the SIFT Tax rules provide that the SIFT Tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5 percent in 2011 and 15 percent in 2012) plus the provincial SIFT tax factor discussed below.

On February 26, 2008, the Minister of Finance announced (the "**Provincial SIFT Tax Proposal**") that instead of basing the provincial component of the SIFT Tax on a flat rate of 13 percent, the provincial component will be based on the general provincial corporate income tax rate in each

province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, our taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of our taxable distributions for the year that our wages and salaries in the province are of our total wages and salaries in Canada; and

- that proportion of our taxable distributions for the year that our gross revenues in the province are of our total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal we would be considered to have a permanent establishment in Alberta only, where the provincial tax rate in 2011 is expected to be 10 percent. Taxable distributions that are not allocated to any province would instead be subject to a 10 percent rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

The long-term effect of the SIFT Tax on us cannot be determined at this time, but may be materially adverse to us and some or all of our Unitholders. There can be no assurance that we will be able to generate sufficient tax pools and/or reorganize our legal and tax structure in order to mitigate, in whole or in part, the expected impact of the SIFT Tax.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions (including, without limitation, the Vault Acquisition and the Canetic Acquisition) depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value in our financial statements.

Incorrect Assessment of the Value of Acquisitions

Acquisitions of oil and gas properties or companies will be based in large part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated.

Management of Growth

We may be subject to growth-related risks, including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse impact on our business, operations and prospects.

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.

For such period of time as we operate in a trust structure, we intend to continue to qualify as a mutual fund trust for purposes of the Tax Act. 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 Unitholders, particularly Non-Residents. See "Risk Factors – Non-Resident Ownership of Trust Units".

New Alberta Royalty Regime

On February 16, 2007, the Alberta government began a review of its royalty regime for oil sands, conventional oil and natural gas and coalbed methane with the stated intention of assessing whether the existing royalty regime was providing Albertans with a fair return on Alberta's natural resources while maintaining an internationally competitive system that allows the Alberta economy to continue to prosper.

On October 25, 2007, the Alberta government released a report titled "The New Royalty Framework" (the " **Report**") containing the government's proposals for Alberta's new royalty regime (the "**Proposed Royalty Regime**"), which is scheduled to take effect on January 1, 2009. The Proposed Royalty Regime includes the following features:

- New, simplified royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity. The formulas eliminate the need for conventional oil and natural gas tiers and several royalty exemption programs.
- A sliding scale will be implemented for oil sands royalty rates ranging from one to nine percent pre-payout and 25 to 40 percent post-payout depending on the price of oil.
- The province will exercise its existing right to receive "royalty-in-kind" on oil sands projects (i.e. raw bitumen delivered to the Crown-operated Alberta Petroleum Marketing Commission in lieu of cash royalties).
- The government will ensure that eligible expenditures and definitions of oil sands projects (also known as "ring fence" definition) that determine when a project has reached payout are tightly and clearly defined. Environmental "costs of doing business" will continue to be recognized as eligible expenditures.
- No grandfathering will be implemented for existing oil sands projects.
- Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009.
- The government will implement "shallow rights reversion" (" **Shallow Rights Reversion**") to maximize the extraction of resources. Under this policy, mineral rights to shallow gas geological formations that are not being developed would revert back to the government and be made available for resale.

As at December 31, 2007, approximately 69.9 percent of our total proved gross reserves and approximately 68.0 percent of our total proved plus probable gross reserves were located in the province of Alberta (including the reserves acquired by us pursuant to the Vault Acquisition and the Canetic Acquisition). Given that the Proposed Royalty Regime has only recently been announced, it is not possible at this time to determine the full impact of the Proposed Royalty Regime on our financial condition and operations, and in particular the extent to which the Proposed Royalty Regime will reduce our funds flow, which will in turn reduce the cash otherwise available for distribution by us to our Unitholders. Penn West's, Canetic's and Vault's reserves and the future net revenue associated therewith as summarized in this Annual Information Form do not reflect the increased royalty rates contemplated by the Proposed Royalty Regime and, after taking the Proposed Royalty Regime into account, such values may be adversely affected.

Furthermore, the Report does not contain any details regarding the implementation of the Alberta government's proposed Shallow Rights Reversion program. Although the government has indicated that it intends to begin a consultation process with industry regarding the implementation of the Shallow Rights Reversion program, no such consultation process has begun as of the date hereof. Furthermore, although it is anticipated that the Alberta government will give existing leaseholders a grace period to make their own plans before opening up shallower zones to other industry participants, the Alberta government has not provided any indication as to how long such a grace period might be. It is therefore not possible at this time to determine the potential impact of the proposed Shallow Rights Reversion program on our financial condition and operations.

We can not provide any assurance that the Proposed Royalty Regime will be implemented in the form proposed in the Report. If changes are made to the Proposed Royalty Regime before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts us in a materially different manner, and that is more adverse to us, than the royalty regime proposed in the Report.

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 SIFT Tax imposed by the Government of Canada will substantially eliminate the competitive advantage that we and other energy trusts have enjoyed relative to our industry competitors in raising capital in a tax-efficient manner. See “Risk Factors – Federal Tax Changes”. To the extent that we are required to use additional funds flow to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the amount of funds flow available for distribution to Unitholders will be reduced.

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 and other debt instruments 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 and other debt instruments are unsecured and we must comply with certain financial debt covenants. The lenders and other debt holders could, in the future, require security over a portion of or substantially all of our assets. Should this occur, in the event that we become unable to pay our debt service charges or otherwise commit an event of default such as bankruptcy, the lender and other debt holders may foreclose on or require us to sell our oil and gas and other assets.

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 based on our projected cost-benefit analysis of maintaining such insurance, 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.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim, which could result in a reduction of the revenue received by the Operating Entities and consequently the funds flow available for distribution to Unitholders.

Expiration of Licenses and Leases

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fail to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse affect on our results of operations and business.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties could subject us 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 funds 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 intend to distribute approximately 60 percent to 70 percent of our net funds flow to Unitholders rather than reinvesting it in reserve additions and production growth or maintenance. 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 funds flow to finance capital expenditures or property acquisitions, the level of funds 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.

Expansion of Operations

The operations and expertise of management are currently focused on oil and gas production and exploration and development in the Western Canadian Sedimentary Basin and, following the completion of Canetic Acquisition, in North Dakota, Montana and Wyoming in the United States. In the future, we may acquire oil and gas properties outside these geographic areas. 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, upgraders 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.

Additional Taxation Applicable to Non-Residents

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the cash distributions or other property paid by us to Unitholders who are Non-Residents of Canada, and these taxes may change from time to time. Since January 1, 2005, a 15 percent Canadian withholding tax is applied to any return of capital portion of distributions made to Non-Resident Unitholders.

Additionally, the reduced "Qualified Dividend" rate of 15 percent tax which has applied to our distributions under current US tax laws is scheduled to expire at the end of 2010 and there is no assurance that this reduced tax rate will be renewed by the US government at such time.

Furthermore, it is anticipated that the implementation of the SIFT Tax may have tax consequences for Non-Residents of Canada that are more adverse than the tax consequences to other classes of Unitholders.

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 PWPL. 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 Internal 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, we are not registered under any trust and loan company legislation as we do 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.

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 a 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 ("CBM") Projects

The engineering, geological, production and associated dewatering techniques employed on CBM projects are relatively new in the Western Canadian Sedimentary Basin and their application to our CBM prone properties is subject to this risk 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.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Penn West, which may be dilutive to Unitholders. In addition, we may determine to redeem the currently outstanding Convertible Debentures for Trust Units or to settle the interest and/or pay the redemption price at maturity of such Convertible

Debentures by issuing additional Trust Units. Accordingly, holders of Trust Units may suffer dilution in the event of any such issuance of Trust Units.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in our exploration, development and production activities and thereby adversely affect our results of operations and business.

Non-Resident Ownership of Trust Units

In order for us to maintain our status as a mutual fund trust under the Tax Act, we must not be established or maintained primarily for the benefit of Non-Residents unless we satisfy the requirements of certain exceptions. The Trust Indenture provides that Penn West will use its best commercial efforts to maintain its status as a mutual fund trust under the Tax Act. Generally speaking, the Tax Act 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 (which is generally interpreted to mean that the majority of unitholders must not be Non-Residents), unless at the relevant time, "all or substantially all" of the trust's property consists of property other than taxable Canadian property (the "**TCP Exception**"). Based on information obtained by us through our transfer agent and financial intermediaries, in February 2008 (and following the completion of the Vault Acquisition and the Canetic Acquisition), we have estimated that approximately 61 percent of our issued and outstanding Trust Units were held by Non-Residents. We have determined that we currently meet 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 us or that the Government of Canada will not introduce new changes or proposals to tax regulations directed at Non-Resident ownership which, given our level of Non-Resident ownership, may result in Penn West losing its mutual fund trust status or could otherwise detrimentally affect Penn West and the market price of the Trust Units. PWPL intends to continue to take the necessary measures in order to ensure Penn West continues to qualify as a mutual fund trust under the Tax Act, as it currently exists. See "Risk Factors – Changes in Legislation".

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any claims have been made in respect of our properties and assets; however, if a claim arose and was successful this could have an adverse affect on our results of operations and business.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. To the extent we are not the operator of our oil and gas properties, we will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Potential Conflicts of Interest

The directors and officers of PWPL are engaged in, and will continue to engage in, other activities in the oil and natural gas industry and, as a result of these and other activities, the directors and officers of PWPL may become subject to conflicts of interest. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of

such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

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.

Limited Ability of Residents in the United States to Enforce Civil Remedies

Both Penn West and PWPL are organized under the laws of Alberta, Canada and have their principal place of business in Canada. Most of the directors and all of the officers of PWPL and the representatives of the experts who provide services to Penn West and PWPL (such as its auditors and its independent reserve engineers), and a substantial portion of the assets of Penn West and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgements of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against Penn West or PWPL or against any of PWPL's directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgement of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Differences in Reporting Practices in Canada and the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves, which is either not generally included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes; however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. The SEC generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to us because we are a Canadian foreign private issuer.

Foreign Exchange Risk of Non-Resident Unitholders

Our distributions are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar weakens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

Asset Write-Downs

Canadian GAAP requires that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in our consolidated financial statements.

Under Canadian 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 funds 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 non-cash charge against net income. 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 funds 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".

Canadian 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, 2007 we had $652.0 million recorded on our balance sheet as goodwill arising out of the Petrofund Acquisition. 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.

Canadian 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.

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.

MATERIAL CONTRACTS

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

(a) the Trust Indenture described under "Information Relating to the Trust – Trust Indenture";

(b) the Administration Agreement referred to under "Information Relating to the Trust – Trust Indenture – Our Management" and "Corporate Governance";

(c) the Debenture Indentures described under "Information Relating to Penn West – Convertible Debentures";

(d) the credit agreement dated January 10, 2008 among PWPL and certain lenders and other parties in respect of Penn West's $4 billion syndicated credit facility, which agreement is described in Note 5 to Penn West's financial statements for the year ended December 31, 2007, which note is incorporated by reference herein; and

(e) the note purchase agreement dated May 31, 2007 among PWPL and the holders of PWPL's US$475 million principal amount of notes, which agreement is described in Note 5 to Penn West's financial statements for the year ended December 31, 2007, which note is incorporated by reference herein.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that Penn West is or was a party to, or that any of Penn West's property is or was the subject of, during the most recently completed financial year, that were or are material to Penn West, and there are no such material legal proceedings that Penn West is currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against Penn West by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against Penn West that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements Penn West entered into before a court relating to securities legislation or with a securities regulatory authority during Penn West's most recently completed financial year.

TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Trust Units is CIBC Mellon Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario. The transfer agent and registrar for the 7.2% Debentures and the 8% 2005 Debentures is Valiant Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario. The transfer agent and registrar for the 6.5% 2005 Debentures is Olympia Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario. The transfer agent and registrar for the 6.5% 2006 Debentures, the 8% 2004 Debentures and the 9.4% Debentures is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of any director or executive officer of PWPL, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Trust Units, or any known associate or affiliate of any such person, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Penn West, except for the matters disclosed in Note 16, Note 17 and under the heading "Related party transactions" of the consolidated financial statements for the years ending 2007, 2006 and 2005, which disclosure is incorporated by reference in this Annual Information Form and 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 report, valuation, statement or opinion made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion 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 (excluding auditors of businesses acquired by us) other than GLJ, our independent engineering evaluator, Sproule, Canetic's and Vault's independent engineering evaluator (GLJ and Sproule each an "**Engineer**" and collectively the "**Engineers**"), and KPMG LLP, our auditors. The registered or beneficial interests, direct or indirect, in any securities or other property of Penn West or of one of its associates or affiliates: (i) held by an Engineer and by the "designated professionals" (as defined in National Instrument 51-102) of the Engineer, when that Engineer prepared the report, valuation, statement or opinion referred to above; (ii) received by an Engineer and by the "designated professionals" of that Engineer, after the time specified above; or (iii) to be received by an Engineer and by the "designated professionals" of that Engineer; in each case, represented less than 1% of each class of our outstanding securities. KPMG LLP is the auditor of Penn West 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 PWPL or of any of our associate or affiliate entities. John A. Brussa, the Chairman of PWPL, is a partner of Burnet, Duckworth & Palmer LLP, a law firm which renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to Penn West may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Penn West's securities and securities authorized for issuance under equity compensation plans, is contained in Penn West's information circular for its most recent annual meeting of Unitholders that involves the election of directors. In addition, additional financial information is provided in Penn West's financial statements and management's discussion and analysis for its most recently completed financial year.

Any document referred to in this Annual Information Form and described as being filed on SEDAR at www.sedar.com and on EDGAR at www.sec.gov (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us by contacting our Investor Relations Department by telephone (toll free: 1-888-770-2633) or by email (investor_relations@pennwest.com).

APPENDIX A-1

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

(Form 51-101F3)

Management of Penn West Petroleum Ltd. (" **PWPL**") 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 are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

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 of PWPL 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 of PWPL 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 Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) William E. Andrew
Chief Executive Officer

(signed) Murray R. Nunns
President and Chief Operating Officer

(signed) Daryl Gilbert
Director and Chairman of the Reserves Committee

(signed) Thomas E. Phillips
Director and Member of the Reserves Committee

March 26, 2008

APPENDIX A-2

GLJ REPORT ON RESERVES DATA

(Form 51-101 F2)

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

1. We have evaluated Penn West's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

2. The reserves data are the responsibility of PWPL'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 by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated and reported on to PWPL'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 7, 2008	Canada	nil	$ 8,100	nil	$ 8,100

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 dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

(signed) GLJ Petroleum Consultants Ltd.
Calgary, Alberta
February 20, 2008

APPENDIX A-3

STATEMENT OF RESERVES DATA – PENN WEST ENERGY TRUST

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, 2007 and the preparation date of the Statement is March 26, 2008. 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 51-101F2 are attached as Appendices A-1 and A-2 to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation prepared by GLJ with an effective date of December 31, 2007 contained in the GLJ Report dated February 20, 2008. 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 forecast prices and costs, not including the impact of any hedging activities. The reserves data conforms with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves. See also "Notes to Reserve Data Tables" below.

The GLJ Report does not take into account the new Alberta royalty regime released on October 25, 2007 titled *"The New Royalty Framework"*, which is scheduled to take effect on January 1, 2009, because sufficient details are not yet available for it to be taken into account. See "Risk Factors – New Alberta Royalty Regime".

The information contained in this Appendix A-3 does not include information with respect to the oil and gas properties and reserves of Vault, which was acquired by Penn West effective January 10, 2008, or Canetic which was acquired by Penn West effective January 11, 2008. Information with respect to the oil and gas properties and reserves of Canetic is set forth in Appendices B-1, B-2 and B-3 to this Annual Information Form. In addition, see "Description of Our Business – Pro Forma Reserves Data of Penn West, Canetic and Vault" for pro forma information in respect of the reserves of Penn West, Canetic and Vault as at December 31, 2007.

All of our reserves are located 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 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 and Resource Estimates" and "Risk Factors – Volatility of Oil and Natural Gas Prices".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2007
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	151,427	137,827	41,849	37,852
Developed Non-Producing	4,433	4,239	2,576	2,189
Undeveloped	34,496	31,002	1,041	973
TOTAL PROVED	190,355	173,069	45,466	41,014
PROBABLE	57,228	51,229	16,383	14,522

TOTAL PROVED PLUS PROBABLE	247,584	224,298	61,849	55,535

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	621,130	510,529	15,221	10,554
Developed Non-Producing	43,350	35,001	967	653
Undeveloped	38,483	31,161	1,100	775
TOTAL PROVED	702,963	576,691	17,288	11,982
PROBABLE	197,772	162,597	5,136	3,733
TOTAL PROVED PLUS PROBABLE	900,734	739,287	22,423	15,715

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	312,018	271,321
Developed Non-Producing	15,201	12,915
Undeveloped	43,051	37,944
TOTAL PROVED	370,270	322,180
PROBABLE	111,709	96,583
TOTAL PROVED PLUS PROBABLE	481,979	418,763

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS(1)

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	Unit Value Before Income Tax Discounted at 10%/year(2) ($/bbl)	($/Mcf)
PROVED							
Developed Producing	10,945	7,543	5,935	4,980	4,336	21.87	3.65
Developed Non-Producing	544	345	255	203	168	19.74	3.29
Undeveloped	1,852	947	599	357	239	14.74	2.46
TOTAL PROVED	13,342	8,836	6,749	5,540	4,743	20.95	3.49
PROBABLE	4,714	2,236	1,352	934	699	13.99	2.33
TOTAL PROVED PLUS PROBABLE	18,055	11,072	8,100	6,474	5,442	19.34	3.22

Notes:
(1) Management of PWPL has estimated that the impact of Alberta's Proposed Royalty Regime, in the form currently proposed, is to decrease the net present values of future net revenue before income taxes by approximately 3 percent to 4 percent using a 10 percent discount rate and using the GLJ forecast prices set forth in this Annual Information Form.
(2) The unit values are based on net reserve volumes.

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

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED					
Developed Producing	9,774	6,991	5,620	4,780	4,201
Developed Non-Producing	435	287	217	176	148
Undeveloped	1,417	740	443	285	191

TOTAL PROVED	11,627	8,018	6,280	5,241	4,540
PROBABLE	3,490	1,702	1,057	749	573
TOTAL PROVED PLUS PROBABLE	15,117	9,720	7,337	5,990	5,113

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Proved Reserves	26,741	3,316	8,927	729	427	13,342	1,715	11,627
Proved Plus Probable Reserves	35,669	4,502	11,529	1,108	474	18,055	2,939	15,117

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE(3) ($/bbl)	UNIT VALUE(3) ($/Mcf)
Proved Reserves	Light and Medium Crude Oil (1)	4,267	22.20	3.70
	Heavy Oil(1)	785	17.91	2.98
	Natural Gas(2)	1,663	19.71	3.28
	Non-Conventional Oil and Gas Activities	34	19.31	3.22
	TOTAL	6,749	20.95	3.49
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	5,074	20.46	3.41
	Heavy Oil(1)	975	16.43	2.74
	Natural Gas(2)	2,009	18.58	3.10
	Non-Conventional Oil and Gas Activities	42	16.98	2.83
	TOTAL	8,100	19.38	3.23

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas and by-products from oil wells.
(3) The unit values are based on net reserve volumes.

Notes to Reserves Data Tables

1. Columns may not add due to rounding.

2. 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, as of a given date, based on:

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

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable.

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 classification of reserves are provided in the COGE Handbook.

Development and Production Status

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 category (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 estimates 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 are 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.

3. **Forecast prices and costs**

NI 51-101 defines "forecast prices and costs" as future prices and costs that are: (i) generally acceptable as being a reasonable outlook of the future; and (ii) if, and only 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 rather than the prices and costs referred to in subparagraph (i).

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, 2007, inflation and exchange rates utilized in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2007
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) %/year	EXCHANGE RATE(2) ($ US equals $1 Cdn)
Forecast										
2008	90.81	89.63	54.34	77.54	6.63	55.30	69.30	91.61	—	1.000
2009	87.00	85.82	52.01	74.24	7.38	52.94	66.35	87.71	2.0	1.000
2010	84.33	83.13	50.38	71.91	7.65	51.25	64.23	84.97	2.0	1.000
2011	82.39	81.18	49.18	70.22	7.65	50.05	62.72	82.97	2.0	1.000
2012	82.13	80.92	49.02	69.99	7.60	49.89	62.53	82.70	2.0	1.000
2013	82.40	81.18	49.71	70.22	7.69	50.05	62.72	82.97	2.0	1.000
2014	83.23	81.99	50.74	70.92	7.88	50.53	63.33	83.80	2.0	1.000
2015	84.08	82.82	51.78	71.63	8.05	51.02	63.95	84.66	2.0	1.000
2016	84.94	83.68	52.84	72.37	8.23	51.53	64.59	85.53	2.0	1.000
2017	86.65	85.37	53.92	73.83	8.41	52.57	65.89	87.26	2.0	1.000
2018	88.38	87.08	55.00	75.31	8.58	53.62	67.21	89.00	2.0	1.000
Thereafter	+2%	+2%	+2%	+2%	+2%	+2%	+2%	+2%	2.0	1.000

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, 2007 were $7.02/Mcf for natural gas, $69.16/bbl for light and medium crude oil, $45.26/bbl for heavy oil and $57.37/bbl for natural gas liquids.

4. **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	
Year	Proved Reserves (MM$)	Proved Plus Probable Reserves (MM$)
2008	199	260
2009	134	186
2010	95	129
2011	72	92
2012	47	64
Total: Undiscounted for all years	729	1,108

We currently expect to fund the development costs of the reserves through internally generated funds flow withheld from distributions.

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 funds flow and could result in negative revisions to our reserves.

The interest and other costs of any 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 currently anticipate that interest or other funding costs would make development of any property uneconomic.

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

6. The forecast price and cost assumptions assumed the continuance of current laws and regulations.

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

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

Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2007, using forecast price and cost estimates derived from the GLJ Report.

RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL(3)			HEAVY OIL(3)			NATURAL GAS(3)		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2006	186,930	50,880	237,810	45,901	14,031	59,932	757,625	203,213	960,838
Extensions	169	72	241	1,999	1,062	3,061	3,749	2,494	6,242
Improved Recovery(1)	3,124	3,120	6,244	2,299	921	3,221	13,306	1,478	14,784
Technical Revisions(2)	3,578	(686)	2,892	1,317	(152)	1,165	23,363	(16,648)	6,716
Discoveries	46	13	59	172	69	241	4,202	1,069	5,271
Acquisitions	11,990	3,685	15,675	1,208	334	1,543	36,037	13,920	49,957
Dispositions	(348)	(109)	(458)	(55)	(23)	(77)	(18,283)	(7,754)	(26,037)
Economic Factors	935	254	1,189	459	140	599	—	—	—
Production	(16,068)	—	(16,068)	(7,835)	—	(7,835)	(117,036)	—	(117,036)
December 31, 2007	190,355	57,229	247,584	45,466	16,383	61,849	702,963	197,771	900,734

Note:

(1) Improved recovery includes the following infill drilling:

Infill Drilling	1,355	1,739	3,094	531	162	693	3,652	1,607	5,259

	NATURAL GAS LIQUIDS(3)			TOTAL OIL EQUIVALENT(3)		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)
December 31, 2006	19,590	5,303	24,893	378,692	104,083	482,775
Extensions	35	11	46	2,827	1,560	4,387
Improved Recovery(1)	223	108	330	7,864	4,395	12,259
Technical Revisions(2)	(679)	(385)	(1,064)	8,109	(3,998)	4,112
Discoveries	73	17	90	991	277	1,268
Acquisitions	565	232	797	19,770	6,571	26,341
Dispositions	(424)	(150)	(574)	(3,874)	(1,574)	(5,448)
Economic Factors	—	—	—	1,394	395	1,788
Production	(2,094)	—	(2,094)	(45,503)	—	(45,503)
December 31, 2007	17,288	5,135	22,423	370,270	111,709	481,978

Notes:

(1) Improved recovery includes the following infill drilling:

Infill Drilling	90	40	129	2,584	2,208	4,792

(2) Technical Revisions includes reclassification of 1,727 Mbbl of proved oil reserves as heavy from light/medium and 1,882 Mbbl proved and probable oil reserves as heavy from light/medium.

(3) Columns may not add due to rounding.

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

The following table discloses, for each product type, the gross volumes of proved undeveloped reserves that were first attributed, net of conversions and revisions, in each of the most recent three financial years and, in the aggregate, before that time.

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	12,682	12,682	195	195	19,064	19,064	529	529
2005	3,420	16,102	—	195	2,122	21,186	117	646
2006	13,081	29,183	210	405	5,632	26,818	160	806
2007	5,313	34,496	636	1,041	11,665	38,483	294	1,100

GLJ has assigned 43 MMboe of proven undeveloped reserves in the GLJ Report under forecast prices and costs, together with $450.9 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first two forecast years of the GLJ Report accounts for $233.1 million, or 52 percent, of the total forecast. These figures increase to $392.8 million or 87 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 Undeveloped Reserves

The following table discloses, for each product type, the gross volumes of probable undeveloped reserves that were first attributed, net of conversions and revisions, in each of the most recent three financial years and, in the aggregate, before that time.

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	1,022	1,022	4	4	1,607	1,607	53	53
2005	7,324	8,346	548	552	8,220	9,827	551	604
2006	10,524	18,870	151	703	4,896	14,723	975	1,579
2007	5,290	24,160	729	1,432	10,896	25,619	257	1,836

GLJ has assigned 32 MMboe of probable undeveloped reserves, which are primarily associated with proved undeveloped reserve assignments but have a less likely probability of being recovered than such associated proved undeveloped reserve assignments.

Significant Factors or Uncertainties

The development schedule of Penn West's undeveloped reserves is based on forecast 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 15,319 net well bores and 1,267 facilities as of December 31, 2007. 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 estimated 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, 2007	1,873	209
Anticipated to be paid in 2008	40	36
Anticipated to be paid in 2009	42	35
Anticipated to be paid in 2010	44	33

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 $1,399 million, and escalated at two percent and discounted at 10 percent, these costs were $156 million.

OTHER OIL AND GAS INFORMATION

Our portfolio of properties as at December 31, 2007 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, 2007. Reserve amounts are stated at December 31, 2007, based on forecast cost and price assumptions as evaluated in the GLJ Report prepared by GLJ. Information in respect of gross and net acres and well counts is as at December 31, 2007, and information in respect of production is for the year ended December 31, 2007 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, 2007 may not directly correspond to the stated production for the year, which only includes production since the date the interests were acquired by us. 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, 2007, 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	36,709	137	59,435	187.4	379.9	250.7	1,253
Plains	35,195	89	50,048	133.9	259.3	177.2	964
Northern	1,820	106	19,509	10.5	261.5	54.1	1,008
Total	73,724	332	128,992	331.9	900.7	482.0	3,225
	57% of daily production	43 % of daily production		69 % of total reserves	31 % of total reserves		

Oil and Natural Gas Properties

Penn West's production and reserves are attributed to more than 200 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 32 percent of Penn West's natural gas production and two percent of its liquids production, based on 2007 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 39 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 1,008,000 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, gas processing plant expansion and the construction of a sales gas line into Alberta to accommodate the increased volumes. Raw throughput of the facility averaged 42 MMcf/d for 2007.

Penn West drilled four wells in the Northern Area in 2007, with 2008 plans focusing on improving field compression and wellbore optimization. In Wildboy, Penn West acquired 74,000 acres of Crown land prospective for shale gas underlying our Wildboy infrastructure. In 2008, Penn West will begin evaluating the acreage with three dimensional seismic and drilling a stratigraphic test well. The Peace River Arch area currently provides approximately three percent of Penn West's total production. In 2007, Penn West drilled four wells in the Buick Creek area. Plans for 2008 are focused on wellbore optimization at Firebird, Spirit River and Cecil Lake, with plans to drill locations for natural gas in the Halfway and Montney formations. Penn West currently holds approximately 76,000 net acres of undeveloped land in the Peace River Arch area.

Central Area

The Central Area currently provides approximately 41 percent of Penn West's natural gas production and 50 percent of its liquids production based on 2007 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 1,253,000 net acres of undeveloped land in the Central Area.

The Central Area is also a significant natural gas producing area, with production of 137 MMcf/d at year-end 2007. 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 2007, we have drilled 81 horizontal wells and 36 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 2008, 24 stratigraphic wells and 20 to 25 net horizontal wells are planned, with capital programs of approximately $55 million, excluding acquisitions.

Central – Pembina

Pembina produces high-netback, long-life, low-decline light oil and liquids-rich natural gas. Approximately 1,222 operated producing wellbores account for 12,100 bbl/d of operated production or nine percent of our 2007 production. Our share of current Pembina area production is approximately 16,350 boe/d including operated and non-operated volumes.

The group of properties is centred on the extensive, long-life Cardium oil pool. The pool is in the secondary recovery (water flood) phase and is continuously being optimized. Our EOR team is currently expanding the Cardium CO_2 pilot to include a new pattern incorporating horizontal producing wells. The pilot expansion should be completed and operational during the second quarter of 2008.

The Pembina team's overall focus is on low-risk drilling and low-cost optimization opportunities that are aimed at adding value to the Trust's Unitholders and reinvesting 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 an extensive network of gas plants, numerous oil batteries and thousands of 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 Nisku.

Penn West drilled 14 gross wells in 2007, with plans for a 2008 drilling program of 16 wells. This drilling program is a mix of shallow Edmonton

gas wells, low-risk Cardium infill wells, development wells and medium depth gas wells. As in 2007, 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. Penn West has a strategic advantage in the area by having operational control over key infrastructure.

Willesden Green is an active development area. The 12 development and exploitation wells planned in 2008 (up from six wells in 2007) are intended to offset natural production declines. We retain deep mineral rights throughout the area, enhancing longer-term exploration potential for Penn West or drilling partners.

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 2007, six infill wells were drilled focusing on the 100 percent working interest Cardium oil and Belly River natural gas pools. For 2008, we plan to drill 12 wells focusing on low risk Cardium infill drilling, liquids rich Manville gas wells and shallow Edmonton gas wells.

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 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 currently under construction.

The CBM pilot has been on production for approximately six months. The pilot wells are currently in the dewatering phase and are performing as expected. Based on industry production experience at the offsetting successful 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 only been partially miscible flooded in the past. The pilot, which consists of two "five spot" patterns, is under construction and will be operational during the second quarter of 2008. 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.

Plains Area

The Plains Area is a shallow depth all season access region with multi-zone potential that supplies 27 percent of Penn West's natural gas production and 48 percent of the liquids based on 2007 exit rate production. In 2007, Penn West drilled 112 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 2008, Penn West plans to drill 155 net wells and holds approximately 964,000 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 2007, investment of $8.7 million funded 125 separate optimization projects. Development drilling added 685 boe/d in new volumes and the optimization projects added 800 boe/d. Complemented by properties at Sugden, Consort, and Ribstone acquired with the Petrofund Acquisition, the Wainwright group of properties generated overall volumes of 17,300 boe/d or approximately 13.5 percent of our 2007 exit production.

Plains – Hoosier – Coleville

Hoosier and Coleville consist of more than 29 producing properties and form one of Penn West's most active development areas. These assets, mainly operated by Penn West, include approximately 2,757 producing wellbores, a high average working interest, extensive Penn West infrastructure and a combined 943,000 acres of lands, of which 348,000 net acres are undeveloped.

Hoosier's primary commodity is cold-pumped conventional heavy oil. The main geological targets are the seismically defined Bakken formation, the Mannville Group and the extensive Viking formation, all at depths shallower than 850 metres. Penn West drilled 49 wells throughout Hoosier in 2007, including 35 vertical wells, five horizontal wells and nine natural gas wells. In the Coleville Bakken pool, Penn West initiated a program during 2007 to replace all of the aging pipeline infrastructure. This program will reduce our exposure to environmental liability by reducing the frequency of pipeline breaks and capturing otherwise vented solution gas. Also, the improved infrastructure will allow us to further optimize the waterflood scheme by targeting water injection to specific areas of the reservoir.

In 2008, Penn West has budgeted $38 million to drill 47 vertical wells and six 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 medium and light oil reserves from a variety of stratigraphic zones producing a total of approximately 8,500 bbl/d. These properties stretch from the Rocky Mountains to western Manitoba and 200 kilometres north from the US border. This large geographic region includes many opportunities for development and optimization.

Penn West acquired a 21.1 percent interest in the Weyburn Unit located in Southeast Saskatchewan in the Petrofund Acquisition. Weyburn is Canada's largest commercial CO_2 enhanced oil recovery project, producing approximately 26,500 bbl/d (approximately 5,650 bbl/d net to Penn West) at December 31, 2007, sourcing CO_2 for injection from a coal gasification plant in North Dakota. Our share of capital costs was $51 million in 2007 decreasing to approximately $46 million in 2008. The application of CO_2 miscible flooding increased the recovery factor from 31 percent under a secondary waterflood scheme to 48 percent under the CO_2 enhanced recovery scheme. With the Petrofund Acquisition, 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 "Additional Information Relating to Reserves Data – Undeveloped Reserves" above.

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, 2007.

	Producing				Non-Producing		Total	
	Oil		Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	7,649	4,132	4,301	2,262	5,432	3,016	17,382	9,410
British Columbia	92	24	630	318	270	129	992	471
Saskatchewan	4,956	3,360	665	547	2,244	1,343	7,865	5,250
Manitoba	145	138	—	—	56	51	201	189
Total	12,842	7,654	5,596	3,127	8,002	4,539	26,440	15,320

Properties with no Attributed Reserves

The following table sets out the unproved properties in which we have an interest as at December 31, 2007.

	Unproved Properties (000s of Acres)	
	Gross	Net
Alberta	2,555	2,148
British Columbia	514	421
Saskatchewan	551	517
Manitoba	140	139
Total	3,760	3,225

We currently have no material work commitments on these lands. The primary lease or extension term on 598,114 net acres of unproved property will expire by December 31, 2008. 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 Internal 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.

The legislation implementing the SIFT Tax received Royal assent on June 22, 2007 with the result that commencing January 1, 2011 taxes could be exigible in the Trust as certain distributions will no longer be a deduction in the calculation of its taxable income. For more information on the SIFT Tax, see "Risk Factors – 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, 2007.

	2007 MM$
Property Acquisitions	
Proved Properties	$ 421.7
Unproved Properties	30.2
Exploration Costs(1)	102.0
Development Costs(2)	529.5
Corporate Costs	35.6
Capital Expenditures	$ 1,119.0
Corporate Acquisitions	21.2
Total Expenditures	$ 1,140.2

Notes:

(1) Costs of land acquired, geological and geophysical capital expenditures and drilling costs for 2007 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, 2007.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	21	19	159	89
Natural Gas	28	22	86	33
Service	17	17	22	13
Dry	4	3	4	3
Total	70	61	271	138

We estimate capital expenditures of approximately $910 million in 2008 to execute our capital programs. The primary components of our programs are described under the heading “Other Oil and Gas information – Oil and Natural Gas Properties”.

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2008 which is reflected in the estimates of gross proved reserves and gross probable reserves disclosed in the tables contained under “Disclosure of Reserves Data” above.

	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	40,203	35,228	20,786	17,990	279,199	221,772	5,593	3,862	113,114	94,042
Proved Developed Non-Producing	812	719	442	353	11,086	8,613	189	131	3,290	2,638
Proved Undeveloped	1,684	1,415	487	427	3,792	2,730	96	71	2,899	2,368
Total Proved	42,698	37,361	21,715	18,770	294,078	233,116	5,878	4,064	119,303	99,048
Total Probable	1,672	1,337	1,376	1,119	15,250	11,446	209	146	5,800	4,510
Total Proved Plus Probable	44,371	38,698	23,091	19,890	309,328	244,562	6,087	4,210	125,103	103,558

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

Production History

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

	Quarter Ended 2007	Year Ended

	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2007
Average Daily Production(1)					
Light and Medium Crude Oil (bbl/d)	42,737	44,078	45,046	45,338	44,310
Heavy Oil (bbl/d)	22,610	21,288	21,922	22,262	22,019
Gas (MMcf/d)	340.4	334.1	315.4	328.1	329.4
NGLs (bbl/d)	6,369	5,558	5,815	5,732	5,866
Combined (boe/d)	128,447	126,599	125,345	128,024	127,098
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	60.93	66.57	74.49	78.20	70.26
Heavy Oil ($/bbl)	41.03	42.45	48.75	48.69	45.26
Gas ($/Mcf)	7.59	7.55	5.86	6.34	6.85
NGLs ($/bbl)	49.81	54.71	58.10	67.38	57.37
Combined ($/boe)	50.08	52.63	52.73	55.44	52.73
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	9.78	10.37	11.46	12.07	10.95
Heavy Oil ($/bbl)	6.27	6.38	7.32	7.18	6.79
Gas ($/Mcf)	1.67	1.64	1.25	1.34	1.48
NGLs ($/bbl)	17.24	18.57	19.49	22.51	19.41
Combined ($/boe)	9.63	9.82	9.46	9.97	9.72
Production Costs (2)(3)					
Light and Medium Crude Oil ($/bbl)	15.37	15.55	15.41	15.73	15.52
Heavy Oil ($/bbl)	12.09	12.15	12.17	12.32	12.18
Gas ($/Mcf)	1.04	1.10	1.15	1.17	1.12
NGLs ($/bbl)	13.63	13.14	13.49	14.15	13.61
Combined ($/boe)	10.70	10.94	11.18	11.35	11.04
Transportation					
Light and Medium Crude Oil ($/bbl)	—	—	—	—	—
Heavy Oil ($/bbl)	0.08	0.03	0.12	0.06	0.07
Gas ($/Mcf)	0.20	0.20	0.18	0.21	0.20
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	0.53	0.52	0.47	0.56	0.52
(Gain)/Loss on Risk Management Contracts					
Light and Medium Crude Oil ($/bbl)	(0.41)	—	0.27	4.36	1.10
Heavy Oil ($/bbl)	—	—	—	—	—
Gas ($/Mcf)	(0.06)	(0.01)	(0.43)	(0.20)	(0.17)
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	(0.29)	(0.03)	(0.98)	1.02	(0.06)

	Quarter Ended 2007				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2007
Netback Received(4)					
Light and Medium Crude Oil ($/bbl)	36.19	40.65	47.35	46.04	42.69
Heavy Oil ($/bbl)	22.59	23.89	29.14	29.13	26.22
Gas ($/Mcf)	4.74	4.62	3.71	3.82	4.22
NGLs ($/bbl)	18.94	23.00	25.12	30.72	24.35
Combined ($/boe)	29.51	31.38	32.60	32.54	31.51

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.

Marketing and Future Commitments

Our marketing approach incorporates the following primary objectives:

- Ensure security of market and avoid production shut-ins due to marketing constraints by dealing with end-users or regionally strategic counterparties wherever possible.

- Ensure protection of our receivables by dealing only with credit worthy counterparties who have been subjected to regular credit reviews.

- Ensure competitive pricing by managing pricing exposures through a portfolio of various terms and geographic basis.

- Ensure optimization of netbacks through careful management of transportation obligations, facility utilization levels, blending opportunities and emulsion handling.

Natural Gas Marketing

In 2007, Penn West received an average price from the sale of natural gas, including hedging gains, of $ 7.02/Mcf compared to $7.47/Mcf realized in 2006. Approximately 87 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 two percent of sales.

Oil and Liquids Marketing

The average quality of our crude oil production is 28 degrees API. Approximately 62 percent of our liquids production can be attributed to light and medium oil, with an average API of 36 degrees. Conventional heavy oil, at 15 degrees average API, comprises approximately 30 percent of total liquids production. Production of NGLs account for approximately eight 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:

	2007		2006	
Quarter ended	Light and Medium Oil ($/bbl)	Heavy Oil ($/bbl)	Light and Medium Oil ($/bbl)	Heavy Oil ($/bbl)
March 31	60.93	41.03	63.42	30.76
June 30	66.57	42.45	73.20	52.85
September 30	74.49	48.75	72.27	52.20
December 31	78.20	48.69	58.51	37.57

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, 2007, 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 may be 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, 2007:

	Notional Volume	Remaining Term	Pricing	Market Value(1) (MM$)
Crude Oil Collars				
WTI Collars	10,000 bbl/d	Jan/08 – Jun/08	US$ 60.00 to 94.55/bbl	$ (9.2)
WTI Collars	20,000 bbl/d	Jan/08 – Dec/08	US$ 67.50 to 79.18/bbl	(109.8)
WTI Collars	10,000 bbl/d	Jul/08 – Dec/08	US$ 67.00 to 79.23/bbl	(24.9)
Natural Gas Collars				
AECO Collars	10,000 GJ/d	Jan/08 – Mar/08	$7.50 to $11.15/GJ	1.1
AECO Collars	50,000 GJ/d	Jan/08 – Oct/08	$6.00 to $7.15/GJ	(0.7)
AECO Collars	50,000 GJ/d	Apr/08 – Oct/08	$6.06 to $6.60/GJ	(2.0)
Electricity Swaps				
Alberta Power Pool	32 MW	2008	$75.02/MWh	—
Alberta Power Pool	30 MW	2009	$76.23/MWh	0.1
Alberta Power Pool	30 MW	2010	$76.23/MWh	(0.7)
Interest Rate Swaps				
	$100.0 million	Jan/08 – Mar/08	4.356%	0.3
	$100.0 million	Jan/08 – Nov/10	4.264%	—

Foreign Exchange Forwards				
8-year term	US$80.0 million	2015	1.00934 CAD/USD	(0.6)
10-year term	US$80.0 million	2017	1.00165 CAD/USD	(0.6)
12-year term	US$70.0 million	2019	0.99125 CAD/USD	(0.2)
15-year term	US$20.0 million	2022	0.98740 CAD/USD	(0.4)
				$ (147.6)

Note:

(1) Unrealized gain (loss) based on calculations using posted rates for similar contracts on December 31, 2007.

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)	2008	2009	2010	2011	2012	Thereafter
Long-term debt	—	—	1,485.4	—	—	457.8
Transportation	13.9	5.8	2.2	0.1	—	—
Transportation ($US)	2.3	2.3	2.3	2.3	2.3	6.4
Power Infrastructure	6.2	4.2	4.2	4.2	4.2	7.6
Drilling Rigs	7.7	2.4	1.2	—	—	—
Purchase Obligations(1)	13.3	13.3	13.3	13.3	13.2	41.1
Office Lease	19.4	19.6	17.3	16.5	16.2	104.3

Note:

(1) These amounts represent estimated commitments of $84.4 million for CO_2 purchases and $23.1 million for processing fees related to interests in the Weyburn unit.

APPENDIX B-1

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

(Form 51-101F3)

Management of Penn West Petroleum Ltd. (“ **PWPL**”) on behalf of Canetic Resources Trust (“ **Canetic**”) is responsible for the preparation and disclosure of information with respect to Canetic’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated Canetic’s reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of PWPL has:

(b) reviewed Canetic’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 of PWPL has reviewed Canetic’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 Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) William E. Andrew
Chief Executive Officer

(signed) Murray R. Nunns
President and Chief Operating Officer

(signed) Daryl Gilbert
Director and Chairman of the Reserves Committee

(signed) Thomas E. Phillips
Director and Member of the Reserves Committee

March 26, 2008

APPENDIX B-2

SPROULE REPORT ON RESERVES DATA

(Form 51-101 F2)

To the Board of Directors of Penn West Petroleum Ltd. (" **PWPL**") on behalf of Canetic Resources Trust (" **Canetic**"):

1. We have evaluated Canetic's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

2. The reserves data are the responsibility of PWPL'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 Canetic evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated and reported on to PWPL'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
Sproule Associates Limited	March 3, 2008	Canada	nil	$ 4,362	nil	$ 4,362

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 dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

(signed) Sproule Associates Limited
Calgary, Alberta

March 3, 2008

APPENDIX B-3

STATEMENT OF RESERVES DATA – CANETIC RESOURCES TRUST

Canetic'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, 2007 and the preparation date of the Statement is March 26, 2008. The Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3 and the Report on Reserves Data by Sproule on Form 51-101F2 are attached as Appendices B-1 and B-2 to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation prepared by Sproule with an effective date of December 31, 2007 contained in the Sproule Canetic Report dated March 3, 2008. The reserves data summarizes Canetic's oil, natural gas liquids and natural gas reserves and the net present values of future net revenue from these reserves using forecast prices and costs, not including the impact of any hedging activities. The reserves data conforms with the requirements of NI 51-101. We engaged Sproule to provide an evaluation of proved and proved plus probable reserves. See also "Notes to Reserve Data Tables" below.

The Sproule Canetic Report does not take into account the new Alberta royalty regime released on October 25, 2007 titled *"The New Royalty Framework"*, which is scheduled to take effect on January 1, 2009, because sufficient details are not yet available for it to be taken into account. See "Risk Factors – New Alberta Royalty Regime".

The majority of Canetic's reserves are located in Canada and, specifically, in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba. Canetic also has minor interests in the United States.

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 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 and Resource Estimates" and "Risk Factors – Volatility of Oil and Natural Gas Prices".

Reserves Data (Forecast Prices and Costs)

The reserves information presented does not report the US reserves separately. The US properties have proved plus probable gross reserves of approximately 6,151 Mboe, or 2.5 percent of Canetic's total reserves, and have a before tax net present value discounted at 10 percent of approximately $76.9 million, or 1.8 percent of the total value of Canetic's reserves.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2007
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	75,945	68,518	14,195	12,908
Developed Non-Producing	834	744	463	395
Undeveloped	3,543	3,213	484	429
TOTAL PROVED	80,322	72,475	15,142	13,732
PROBABLE	30,459	27,192	4,220	3,783
TOTAL PROVED PLUS PROBABLE	110,781	99,666	19,362	17,515

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	360,249	283,443	10,994	7,767
Developed Non-Producing	22,813	17,301	385	281
Undeveloped	20,162	15,516	259	172
TOTAL PROVED	403,224	316,260	11,638	8,221
PROBABLE	194,709	153,250	4,785	3,386
TOTAL PROVED PLUS PROBABLE	597,932	469,510	16,423	11,606

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	161,176	136,434
Developed Non-Producing	5,484	4,303

Undeveloped	7,646	6,399
TOTAL PROVED	174,306	147,137
PROBABLE	71,915	59,902
TOTAL PROVED PLUS PROBABLE	246,221	207,039

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS(1)

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	Unit Value Before Income Tax Discounted at 10%/year(2) ($/bbl)	($/Mcf)
PROVED							
Developed Producing	5,429	4,023	3,266	2,789	2,457	23.94	3.99
Developed Non-Producing	123	98	82	70	61	19.05	3.18
Undeveloped	169	130	101	79	62	15.73	2.62
TOTAL PROVED	5,721	4,251	3,449	2,938	2,579	23.44	3.91
PROBABLE	2,502	1,380	913	666	516	15.23	2.54
TOTAL PROVED PLUS PROBABLE	8,223	5,631	4,362	3,604	3,095	21.07	3.51

Notes:

(1) Management of PWPL has estimated that the impact of Alberta's Proposed Royalty Regime, in the form currently proposed, is to decrease the net present values of future net revenue before income taxes by approximately 2 percent to 3 percent using a 10 percent discount rate and using the Sproule forecast prices set forth in this Annual Information Form.

(2) The unit values are based on net reserve volumes.

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

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED					
Developed Producing	5,133	3,886	3,194	2,747	2,431
Developed Non-Producing	106	87	74	64	57
Undeveloped	159	122	95	74	58
TOTAL PROVED	5,398	4,095	3,363	2,886	2,546
PROBABLE	1,960	1,105	746	555	437
TOTAL PROVED PLUS PROBABLE	7,357	5,200	4,109	3,441	2,983

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Proved Reserves	11,455	1,708	3,495	160	371	5,721	323	5,398
Proved Plus Probable Reserves	16,557	2,501	5,112	292	428	8,223	866	7,357

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE(3) ($/bbl)	($/Mcf)
Proved Reserves	Light and Medium Crude Oil (1)	2,282	26.40	4.40
	Heavy Oil(1)	269	18.90	3.15
	Natural Gas(2)	865	19.70	3.28
	Non-Conventional Oil and Gas Activities (CBM)	34	12.90	2.15
	TOTAL	3,450	23.40	3.90
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	2,832	23.80	3.97
	Heavy Oil(1)	322	17.80	2.97
	Natural Gas(2)	1,140	17.90	2.98
	Non-Conventional Oil and Gas Activities (CBM)	68	10.40	1.73
	TOTAL	4,362	21.10	3.52

Notes:

(1) Including solution gas and other by-products.

(2) Including by-products but excluding solution gas and by-products from oil wells.
(3) The unit values are based on net reserve volumes.

Notes to Reserves Data Tables

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserves estimates presented in the Sproule Canetic 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, as of a given date, based on:

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

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable.

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 classification of reserves are provided in the COGE Handbook.

Development and Production Status

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 category (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 estimates 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 are 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.

3. **Forecast prices and costs**

NI 51-101 defines "forecast prices and costs" as future prices and costs that are: (i) generally acceptable as being a reasonable outlook of the future; and (ii) if, and only 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 rather than the prices and costs referred to in subparagraph (i).

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, 2007, inflation and exchange rates utilized in the Sproule Canetic Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2007
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) %/year	EXCHANGE RATE(2) ($US equals $ 1 Cdn)
Forecast										
2008	90.81	89.63	54.34	77.54	6.63	55.30	69.30	91.61	—	1.000
2009	87.00	85.82	52.01	74.24	7.38	52.94	66.35	87.71	2.0	1.000
2010	84.33	83.13	50.38	71.91	7.65	51.25	64.23	84.97	2.0	1.000
2011	82.39	81.18	49.18	70.22	7.65	50.05	62.72	82.97	2.0	1.000
2012	82.13	80.92	49.02	69.99	7.60	49.89	62.53	82.70	2.0	1.000
2013	82.40	81.18	49.71	70.22	7.69	50.05	62.72	82.97	2.0	1.000
2014	83.23	81.99	50.74	70.92	7.88	50.53	63.33	83.80	2.0	1.000
2015	84.08	82.82	51.78	71.63	8.05	51.02	63.95	84.66	2.0	1.000
2016	84.94	83.68	52.84	72.37	8.23	51.53	64.59	85.53	2.0	1.000
2017	86.65	85.37	53.92	73.83	8.41	52.57	65.89	87.26	2.0	1.000
2018	88.38	87.08	55.00	75.31	8.58	53.62	67.21	89.00	2.0	1.000
Thereafter	+2%	+2%	+2%	+2%	+2%	+2%	+2%	+2%	2.0	1.000

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, 2007 were $7.39/Mcf for natural gas, $65.33/bbl for light and medium crude oil, $46.43/bbl for heavy oil and $49.34/bbl for natural gas liquids.

4. **Future Development Costs**

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

Year	Forecast Prices and Costs Proved Reserves (MM$)	 Proved Plus Probable Reserves (MM$)
2008	89	135
2009	48	119
2010	9	16
2011	5	8
2012	5	5
Total: Undiscounted for all years	160	292

Penn West currently expects to fund the development costs of the reserves through internally generated funds flow withheld from distributions.

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 Sproule Canetic Report. Failure to develop those reserves would have a negative impact on future production and funds flow and could result in negative revisions to Canetic's reserves.

The interest and other costs of any 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 currently anticipate that interest or other funding costs would make development of any property uneconomic.

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

6. The forecast price and cost assumptions assumed the continuance of current laws and regulations.

7. All factual data supplied to Sproule was accepted as represented. No field inspection was conducted.

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

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule 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 Sproule Canetic 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

The following table discloses, for each product type, the gross volumes of proved undeveloped reserves that were first attributed, net of conversions and revisions, in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbl) First Attributed	 Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	 Cumulative at Year End	Natural Gas (MMcf) First Attributed	 Cumulative at Year End	NGLs (Mbbl) First Attributed	 Cumulative at Year End
Prior thereto	1,293	1,293	—	—	4,060	4,060	48	48
2005	6,924	8,217	346	346	13,694	17,754	257	304
2006	3,440	11,657	1,181	1,527	45,857	63,611	613	917
2007	—	3,543	—	484	—	20,162	—	259

Sproule has assigned 7.7 MMboe of proven undeveloped reserves in the Sproule Canetic Report under forecast prices and costs, together with $109.2 million of associated undiscounted future capital expenditures. Proven undeveloped capital

spending in the first two forecast years of the Sproule Canetic Report accounts for $105.6 million, or 97 percent, of the total forecast. These figures increase to $108.4 million or 99 percent, during the first five years of the Sproule Canetic Report.

Probable Undeveloped Reserves

The following table discloses, for each product type, the gross volumes of probable undeveloped reserves that were first attributed, net of conversions and revisions, in each of the most recent three financial years and, in the aggregate, before that time.

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	1,127	1,127	—	—	2,918	2,918	32	32
2005	3,254	4,381	96	96	5,005	7,923	97	128
2006	476	4,857	446	542	30,981	38,904	282	410
2007	—	1,344	—	135	—	9,736	—	106

Sproule has assigned three MMboe of probable undeveloped reserves, which are primarily associated with proved undeveloped reserve assignments but have a less likely probability of being recovered than such associated proved undeveloped reserve assignments.

Significant Factors or Uncertainties

The development schedule of Canetic's undeveloped reserves is based on forecast 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 Canetic's reserves data. However, Canetic'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.

Canetic's total inventory is estimated at 5,660 net well bores and 561 facilities as of December 31, 2007. 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 estimated salvage values, that Penn West expects to incur, including wells that extend beyond the 50-year limit in the Sproule Canetic 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, 2007	777	87
Anticipated to be paid in 2008	20	18
Anticipated to be paid in 2009	21	17
Anticipated to be paid in 2010	22	17

The above table includes certain abandonment and reclamation costs, net of salvage values, not included in the Sproule Canetic 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 $347 million, and escalated at two percent and discounted at 10 percent, these costs were $39 million.

OTHER OIL AND GAS INFORMATION

Canetic's portfolio of properties as at December 31, 2007 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 Canetic's principal oil and natural gas properties as at December 31, 2007. Reserve amounts are stated at December 31, 2007, based on forecast cost and price assumptions as evaluated in the Sproule Canetic Report prepared by Sproule. Information in respect of gross and net acres and well counts is as at December 31, 2007, and information in respect of production is for the year ended December 31, 2007 except where indicated otherwise. Due to the fact that Canetic has been active at acquiring additional interests in its principal properties, the working interest share and interest in gross and net acres and wells as at December 31, 2007 may not directly correspond to the stated production for the year, which only includes production since the date the interests were acquired by Canetic. 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 Canada and, specifically, in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba. Canetic has minor interests in the United States.

The properties represent 100 percent of the total net proved plus probable reserves as assigned by Sproule in the Sproule Canetic 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 Canetic's reported average daily production and proved plus probable reserves, as at December 31, 2007, 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	7,497	48.0	15,490	20.7	126.5	41.8	111
Northern	3,697	44.9	11,176	19.8	181.2	50.0	245
Rocky	5,000	67.3	16,224	19.7	173.3	48.6	127
Southern	12,593	25.9	16,905	42.6	85.6	56.9	179
Williston Basin	11,581	8.2	12,945	43.7	31.3	49.0	112
Total	40,368	194.3	72,740	146.5	597.9	246.3	774
% of daily production/total reserves	56%	44%	100%	60%	40%	100%	

Oil and Natural Gas Properties

Canetic's production and reserves are attributed to more than 250 producing properties. No single property accounts for more than 10 percent of Canetic's reserves. A general discussion of Canetic's operations and activities in each of Canetic's core areas follows.

Williston Basin District

The Williston Basin district provides Canetic with 17 percent of its total production. Located primarily in southeast Saskatchewan, with minor properties in Manitoba, North Dakota, Montana and Wyoming, this area continues to be an active area providing high netback light oil from legacy assets. A total of 55 (29.9 net) wells were drilled in 2007, including 37 (16.5 net) oil wells and 16 (13.3 net) CBM wells. Plans are to drill 17 wells in this area in 2008 targeting high netback, light oil.

Greater Queensdale, Saskatchewan

The Greater Queensdale assets are located in southeast Saskatchewan about 100-150 kilometres north and east of Estevan. This area includes the Ingoldsby, Queensdale, Gainsborough, Cantal and Edenvale properties.

The main producing assets of this area include portions of the Queensdale Frobisher-Alida Pool, Alida West Frobisher-Alida Pool (Edenvale), Cantal Frobisher-Alida Pool, Nottingham South Frobisher-Alida Pool, and the Ingoldsby Frobisher Alida Pool. The light oil (30-38°API) is produced from the Frobisher-Alida beds at 1,000 to 1,400 metres in depth. Substantially all of the production in which Canetic has an interest is pipelined to company owned central facilities including oil, gas and water separation and treating equipment, crude oil pipeline connection, and salt water disposal facilities. Canetic has a working interest in the NAL-operated Nottingham gas plant at 8-17-5-32 W1M and associated gas-gathering system where the majority of the area's conserved solution gas is processed.

In 2007, Canetic drilled a successful seven (six net) horizontal well program focusing on the highly deliverable Alida formation on these legacy assets. Plans are in place for a six well operated program in 2008.

North Dakota and Montana, USA

The properties located in eastern Montana and southwest North Dakota, USA are about 200 to 300 kilometres south of Estevan. Canetic has working interests ranging from 19 percent to 100 percent.

The main producing assets in this area include portions of the Brush Mountain Ratcliffe Pool, Tracy Mountain Tyler Pool and Davis Creek Madison Pool. The light oil (35-42° API) is produced from the Mississippian Madison and Pennsylvanian Tyler beds at 2,500 to 3,000 metres in depth.

Substantially all of the production in which Canetic has an interest is produced to single well batteries where oil, water and gas are separated; gas is consumed as well site fuel or flared. Oil and water are trucked for sale and disposal respectively.

Wyoming, USA – Powder River Basin Coalbed Methane

The Wyoming properties are located in the Powder River Basin, north of Casper. The properties are comprised of 11,298 net acres of undeveloped land with an average working interest of 50%. During 2007, 16 (13.3 net) development Coalbed Methane ("**CBM**") wells were drilled on these properties. Assets at Big Bend, North Carson, Coal Gulch, and Kane target the Big George, Anderson, Canyon/Cook, Wall/Pawnee and Wyodak coals at depths ranging from 100 to 700 metres.

Southern District

The Southern District includes properties located in southern and eastern Alberta and in western to southwestern Saskatchewan. Assets vary throughout this district ranging from medium to light crude oil in southern Alberta and southwest Saskatchewan to heavy oil properties in the Lloydminster area. The area provides Canetic with 24 percent of its production and continues to be an active area for growth. Highlights of the Southern District include light oil development on royalty free lands in southern Alberta and a royalty holiday on horizontal drilling in the Leitchville area of southwest Saskatchewan. Canetic exited the year producing 18,000 boe/d in the Southern District. A total of 58 (37.4 net) wells were drilled in 2007, including 43 (35.2 net) oil wells and 14 (1.2 net) gas wells. One well was drilled and abandoned.

Countess, Alberta

The Countess properties are located in southern Alberta, approximately 130 kilometres southeast of Calgary. The properties in this area have a working interest between 50 and 100 percent for the oil assets and 17.5 to 100 percent for the gas assets.

These assets are comprised of Mannville oil and shallow Medicine Hat/Milk River gas. The gas wells are drilled at an average depth of 550 metres. Canetic gas handling facilities at Countess are comprised of a compressor and processing facility and several booster compressors. The compression facilities boost the gas to sales pipeline operating pressures.

The majority of the Countess oil production is obtained from the Rosemary Lower Mannville Z and RR oil pools and the Duchess Lower Mannville X and VVV oil pools, which are currently under active waterflood schemes. The medium oil (26-33° API) is produced from Lower Mannville sandstones at 1,100 to 1,200 metres in depth.

Substantially all of the Countess oil production is pipelined to one of two 100 percent working interest central facilities located at Rosemary and Duchess. The central facilities include oil, gas and water separation and treating equipment, a crude oil pipeline connection, salt water disposal facilities, and solution gas gathering facilities. A small portion of the production is produced to single well batteries where oil and water are separated and trucked to various area facilities for processing and sale.

Leitchville, Southwest Saskatchewan

Located near Shaunavon, Saskatchewan approximately 450 kilometres southeast of Calgary, this area became a very active area for Canetic in 2007. The emergence of the Lower Shaunavon play, unlocked by multi-stage horizontal fracture stimulation technology, triggered a flood of activity by Canetic which included the drilling of 10 (nine net) wells and actively acquiring undeveloped acreage in 2007. The Lower Shaunavon is found at a depth of roughly 1,400 metres. Horizontal sections average between 1,000 and 1,200 metres in length. The medium quality (23 degree API) crude is produced into single well batteries. Plans are in place to initiate facility development to limit the proliferation of single well batteries. For 2008, Penn West plans to continue to acquire land and have an active drilling program. A minimum of 18 wells are slated to be spud throughout the year.

Furness, Saskatchewan

The greater Furness area is located in western Saskatchewan in Townships 48 and 49, Ranges 26 through 28 W3M. Furness was acquired late in 2003 by Canetic pursuant to the acquisition of Exodus Energy Ltd. and is primarily a heavy oil field. The primary producing zone of interest is the Sparky Sand, with additional production provided from the McLaren and General Petroleum Formations.

Canetic has a 75 percent working interest in a central oil battery that is connected to a sales oil pipeline. The battery is located at 14-08-048-27W3M and is capable of handling 1,600 bbl/d of oil.

In 2007, a successful seven well heavy oil program was drilled in the area which has led to additional follow up opportunities. In 2008, Penn West plans to drill between 14 and 20 wells in the Furness area targeting these opportunities.

Central District

The Central district includes properties located in western and west-central Alberta. Major assets are found in properties located in Pembina, Corbett, Bigoray and Acheson. Production for the area exited the year at 15,109 boe/d and accounted for roughly 20 percent of Canetic's overall production. The area is characterized by light oil and liquids-rich gas. CBM development potential on 100 percent working interest lands in the Corbett area also lies in this district. In 2007, a total of 52 (20.6 net) wells were drilled in the Central district including 26 (10.8 net) oil wells and 20 (8.7 net) gas wells. Six (one net) service wells were drilled for disposal purposes.

Acheson, Alberta

The Acheson area is west of Edmonton and includes interests in the Acheson D-3a Unit, the Acheson Lower Cretaceous Unit No. 1, the Acheson North D-2 Pool Unit and non-unit production. Canetic's overall working interest in the area is 99.7 percent.

Gas is processed at the 100 percent working interest operated 5-2-53-26W4M Acheson gas plant, capable of processing 24 MMcf/d of gas. The oil from the 100 percent owned Acheson field is processed at the unit battery and fluid handling facility located at the 5-2-53-26W4 site.

Acheson is a multi-zone area with production coming from the Leduc, Nisku, Detrital, Basal Quartz and Viking zones. The Leduc Formation is characterized by the development of numerous isolated reef complexes and a broad carbonate shelf, all of which developed on the Cooking Lake platform and is responsible for the majority of Acheson's current production. The D-3a Pool started blow down in June 2003 by the controlled production of reservoir and injected hydrocarbons following the termination of an enhanced recovery scheme to increase the recovery of original oil reserves.

In 2007, this property continued to be an active part of Canetic's budget with aggressive optimization projects targeting up-hole oil and gas recompletions, as well as an 11 (8.8 net) well program targeting light oil in the Detrital formation. In 2008, a seven to 13 well drilling program is scheduled for early in the year.

Corbett Creek, Alberta

The Corbett Creek area is located approximately 125 kilometres northwest of the city of Edmonton. Working interests vary from 40 to 100 percent in the Mannville CBM play that has developed in the area over the past few years. Canetic has both operated and non-operated interests in this play and participated with one joint venture partner in 2007 in the drilling of nine wells (3.7 net). Production is obtained by drilling single to multi-leg horizontals targeting a two to three-metre thick coal at approximately 975 metres total vertical depth. Horizontal legs can be over 1,500 metres in length.

Rocky District

The Rocky district includes properties located in west central Alberta. Production exited 2007 at over 16,000 boe/d, which accounts for roughly 21 percent of Canetic's overall production. The area is characterized by light oil properties in Willesden Green, Gilby and Innisfail, and by large gas reservoirs in the Hoadley/Ferrybank area. In total, 37 (17 net) wells were drilled on these properties during 2007, including nine (1.8 net) oil wells and 28 (15.1 net) gas wells.

Willesden Green, Alberta

The Willesden Green area is located approximately 125 kilometres southwest of Edmonton. The properties include unit and non-unit interests, with the majority of the production operated and with high working interests. The unit interests consist of four producing oil units, with two large operated units and one wholly owned project area producing light oil (41° API) from

the Cardium formation. Two other units (one operated) produce long-life light crude oil and natural gas from the Viking formation. The properties have opportunities for infill drilling on 160-acre spacing units, opportunities to enhance water flood performance, and several stimulation candidates. The non-unit interests produce light gravity crude oil from the Cardium formation and Mannville groups, and natural gas from the Scollard, Belly River, Cardium, Ellerslie, Ostracod, Rock Creek and Nordegg formations. This is a multi-target area with shallow to moderate drill depths and a large concentrated land position with the majority of the lands operated. There are also deeper Mannville drilling targets defined by seismic data, as well as many prospects in the shallower Belly River, Edmonton, Paskapoo and Scollard formations. Canetic owns the facilities associated with the production, as well as a 21.7 percent interest in the Imperial Oil Ltd. Willesden Green natural gas plant. Canetic also owns a 20 MMcf/d gas processing facility, with pipeline infrastructure that allows Canetic to process the majority of our production in this area in our owned gas plant. This plant was constructed in late 2006 and early 2007, and was commissioned in February 2007.

In 2007, Canetic participated in a successful 11 (eight net) well drilling program in the area targeting natural gas in multi-zone horizons.

Hoadley/Ferrybank, Alberta

The Hoadley — Ferrybank area is located 90 kilometres southwest of Edmonton. This property was purchased by Canetic in 2006 through the acquisition of interests in oil and natural gas reserves and associated facilities located in Alberta and British Columbia. Production is entirely natural gas and associated liquids primarily from the Hoadley Barrier Bar complex in the Glauconite formation. Other producing horizons include the Edmonton Sand, the Ellerslie, and Colony. This property includes 204,000 net developed and undeveloped acres with an average working interest of approximately 67 percent, with 90 percent of the production operated by Canetic. Canetic operates 37 compressors in the area and has ownership in nine others. Gas is processed primarily through the Rimbey plant operated by Keyera Energy Ltd. Canetic has a 41 percent ownership in the Encana Oil and Gas Partnership operated Ferrybank plant at 2-1-44-28 W4 that has a capacity of 35 mmcf/d. Canetic has a 13.24 percent ownership in the Mikwan Plant operated by Vermillion Resources Ltd. that has a capacity of 9.5 mmcf/d.

In 2007, Canetic drilled a successful five (4.5 net) well program targeting glauconite gas. In 2008, a six-well program is scheduled.

Northern District

The Northern district includes properties located in northwest Alberta and northeast British Columbia. Exit volumes in 2007 totalled 12,500 boe/d of production, representing approximately 17 percent of Canetic's total production. This district is characterized by liquids-rich gas in the Pouce Coupe, Clarke Lake, Fort St. John and Buick prospect areas, and light oil properties in Pouce and Mitsue. In total 30 (6.61 net) wells were drilled on these properties during 2007, including 10 (0.53 net) oil wells and 16 (4.72 net) gas wells. Four (1.36 net) wells were dry and abandoned.

Pouce Coupe, Alberta

The Pouce Coupe properties are located approximately 80 kilometres northwest of Grande Prairie. Canetic operates the Pouce Coupe South Boundary 'B' Unit No. 2 with a 62.8 percent working interest. This high netback, light oil unit includes an oil battery and water injection facility, as well as amine, refrigeration and gas compression facilities. Production within the unit is obtained from the Boundary Lake member of the Charlie Lake formation. Canetic also holds a 20.793 percent working interest in the Pouce Coupe South Boundary B Unit operated by Enerplus Resources Corporation. Non-unit production consists of wells with interests ranging from a gross overriding royalty to a 78.75 percent working interest. Producing formations primarily include the Doig, Bluesky, Gething, Baldonnel, Halfway and Boundary Lake.

Fort St. John, British Columbia

The Fort St. John properties are primarily located in the Fort St. John area in northeast British Columbia. The principal properties are within a 20 kilometre radius of Fort St. John. Canetic has an average working interest of 55 percent. Canetic also has 50 percent and 65 percent working interests, respectively, in two operated compressor stations and 38.44 percent and 27 percent working interests, respectively, in a further two non-operated compressor stations. In September of 2006, Canetic

obtained additional production in this area through the Samson Acquisition. Working interests average 57 percent in this new acreage and Canetic operates 79 percent of its production. Major fields include Stoddart, Monias, Airport, and Wilder. Producing horizons include Halfway, Doig, and Belloy. Canetic obtained operatorship in 10 compressors through this transaction and has additional ownership in 7 more. All gas is processed through Duke Midstream.

Fireweed/Buick Creek, British Columbia

The Fireweed/Buick Creek properties are located approximately 75 kilometres north and northwest of Fort St. John in northeast British Columbia. Canetic obtained a large land position through the Samson Acquisition in September of 2006. Canetic has an average working interest of 57 percent in the new properties and operates 91 percent of its production. The majority of production comes from the Dunlevy Sand with minor production from the Doig, Halfway, Bluesky, and Baldonnel horizons. Canetic operates nine compressors in the area and has additional ownership in five others. All gas is processed through Duke Midstream.

Clarke Lake

The Clarke Lake properties are located approximately 50 kilometres south and east of Fort Nelson in northeast British Columbia. Canetic has a small 100 percent working interest land position adjacent to the Clarke Lake Slave Point pool. In 2007, Canetic drilled three (three net) wells targeting the Slave Point formation with a 66.7 percent success rate. Production was tied in to Canetic's facility.

Additional Information

None of Canetic'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 "Additional Information Relating to Reserves Data – Undeveloped Reserves" above.

Oil And Gas Wells

The following table sets forth the number and status of wells in which Canetic had a working interest as at December 31, 2007.

	Producing				Non-Producing		Total	
	Oil		Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,154	1,170	2,103	1,164	1,718	587	6,975	2,921
British Columbia	69	25	273	150	77	24	419	199
Saskatchewan	3,151	1,846	332	58	875	245	4,358	2,149
Manitoba	544	192	—	—	162	57	706	249
United States	26	12	230	89	87	41	343	142
Total	6,944	3,245	2,938	1,461	2,919	954	12,801	5,660

Properties with no Attributed Reserves

The following table sets out the unproved properties in which Canetic had an interest as at December 31, 2007.

	Unproved Properties (000s of Acres)	
	Gross	Net
Alberta	658	398
British Columbia	214	127
Saskatchewan	194	142
Manitoba	7	3
Wyoming	22	1
Montana	2	1
North Dakota	27	23
Total	1,124	695

We currently have no material work commitments on these lands. The primary lease or extension term on 169,406 net acres of unproved property will expire by December 31, 2008. 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.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds) related to Canetic's activities for the year ended December 31, 2007.

	2007 MM$
Property Acquisitions	
Proved Properties	$ 81.6
Unproved Properties	31.3
Exploration Costs(1)	2.4
Development Costs(2)	417.7
Corporate Costs	8.1
Capital Expenditures	$ 541.1

Notes:

(1) Costs of land acquired, geological and geophysical capital expenditures and drilling costs for 2007 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 Canetic participated in during the year ended December 31, 2007.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	3	2	122	63
Natural Gas	11	6	87	38
Service	—	—	8	1
Dry	—	—	5	2
Total	14	8	222	104

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2008 which is reflected in the estimates of gross proved reserves and gross probable reserves disclosed in the tables contained under "Disclosure of Reserves Data" above.

	Light and Medium Oil (bbl/d) Gross	Heavy Oil (bbl/d) Gross	Natural Gas (Mcf/d) Gross	Natural Gas Liquids (bbl/d) Gross	Total (Boe/d) Gross
Proved Producing	26,683	4,988	172,236	5,128	65,503
Proved Developed Non-Producing	153	85	6,456	94	1,410
Proved Undeveloped	810	111	3,055	41	1,473
Total Proved	27,646	5,184	181,747	5,263	68,386
Total Probable	1,615	224	9,635	253	3,719
Total Proved Plus Probable	29,261	5,408	191,382	5,516	72,105

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

Information – Principal Properties".

Production History

The following tables summarize certain information in respect of Canetic's production, product prices received, royalties paid, production costs and resulting netback for the periods indicated below:

	Quarter Ended 2007				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2007
Average Daily Production(1)					
Light and Medium Crude Oil (bbl/d)	28,843	27,989	26,349	29,869	28,260
Heavy Oil (bbl/d)	7,578	7,939	8,229	4,467	7,048
Gas (MMcf/d)	220.1	211.0	205.7	182.0	204.6
NGLs (bbl/d)	6,916	6,664	5,711	6,082	6,339
Combined (boe/d)	80,027	77,765	74,572	70,755	75,751
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	60.82	64.36	75.02	75.63	68.92
Heavy Oil ($/bbl)	43.93	44.00	48.63	50.96	46.43
Gas ($/Mcf)	7.65	7.72	5.33	6.40	6.81
NGLs ($/bbl)	43.12	46.85	50.60	57.95	49.34
Combined ($/boe)	50.85	52.62	50.45	56.59	52.55
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	9.89	9.86	13.11	13.44	11.57
Heavy Oil ($/bbl)	5.77	5.66	7.06	7.86	6.45
Gas ($/Mcf)	1.55	1.71	0.87	1.00	1.30
NGLs ($/bbl)	10.33	9.14	13.34	21.18	13.29
Combined ($/boe)	9.27	9.54	8.82	10.57	9.53
Production Costs (2)(3)					
Light and Medium Crude Oil ($/bbl)	11.91	13.64	15.12	16.85	14.39
Heavy Oil ($/bbl)	15.72	10.74	12.98	15.18	14.43
Gas ($/Mcf)	1.37	1.58	1.34	1.99	1.56
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	9.55	10.29	10.48	13.19	10.83
Transportation					
Light and Medium Crude Oil ($/bbl)	0.39	0.24	0.31	0.27	0.30
Heavy Oil ($/bbl)	0.36	0.21	0.29	0.31	0.29
Gas ($/Mcf)	0.29	0.20	0.25	0.27	0.25
NGLs ($/bbl)	0.34	0.24	0.28	0.30	0.29
Combined ($/boe)	0.99	0.67	0.86	0.86	0.85

	Quarter Ended 2007				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2007
(Gain)/Loss on Risk Management Contracts					
Light and Medium Crude Oil ($/bbl)	0.28	1.53	3.96	8.78	3.59
Heavy Oil ($/bbl)	—	—	—	—	—
Gas ($/Mcf)	(0.23)	(0.29)	(1.31)	(0.51)	(0.58)
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	(0.52)	(0.08)	(1.77)	2.96	0.10
Netback Received(4)					
Light and Medium Crude Oil ($/bbl)	38.35	39.09	42.52	36.29	39.07
Heavy Oil ($/bbl)	22.08	27.39	28.30	27.61	26.26
Gas ($/Mcf)	4.67	4.52	4.18	3.65	4.28
NGLs ($/bbl)	32.45	37.47	36.98	36.47	35.76
Combined ($/boe)	31.56	32.20	32.06	29.01	31.24

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.

Marketing and Future Commitments

Natural Gas Marketing

In 2007, Canetic received an average price from the sale of natural gas, including hedging gains, of $ 7.39/Mcf compared to $7.62/Mcf realized in 2006.

Oil and Liquids Marketing

The average quality of Canetic's crude oil production is 31(o) API. Approximately 68 percent of Canetic's liquids production can be attributed to light and medium oil, with an average API of 35(o). Conventional heavy oil, at 17(o) average API, comprises approximately 17 percent of total liquids production. Production of NGLs accounts for approximately 15 percent of total liquids production.

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

	2007		2006	
Quarter ended	Light and Medium Oil ($/bbl)	Heavy Oil ($/bbl)	Light and Medium Oil ($ /bbl)	Heavy Oil ($ /bbl)
March 31	60.82	43.93	58.01	33.26
June 30	64.36	44.00	70.07	50.36
September 30	75.02	48.63	70.17	50.54
December 31	75.63	50.96	55.08	39.76

Forward Contracts

As at December 31, 2007, Canetic 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 may be 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, 2007:

	Notional Volume	Remaining Term	Pricing	Market Value(1) (MM$)
Crude Oil				
WTI Collars	12,000 bbl/d	Jan/08-Dec/08	US$64.17-$81.49/bbl	(57.4)
WTI Swaps	750 bbl/d	Jan/08-Dec/08	US$71.73/bbl	(5.7)
Natural Gas				
AECO Collars	90,000 GJ/d	Jan/08-Mar/08	$7.00 - $11.23/GJ	6.2
AECO Swaps	70,000 GJ/d	Apr/08-Oct/08	$6.41/GJ	(0.5)
				(57.4)

Note:

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

Exhibit 99.2

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, 2007 and 2006. The date of this MD&A is March 6, 2008.

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

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

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

Measures including funds flow, funds flow per unit-basic, funds flow per unit-diluted and netbacks included in this MD&A are not defined in generally accepted accounting principles ("GAAP") and do not have a standardized meaning prescribed by GAAP; accordingly, they may not be comparable to similar measures provided by other issuers. Management utilizes funds flow and netbacks to assess financial performance, to allocate its capital among alternative projects and to assess its capacity to fund distributions and future capital programs. Reconciliations of non-GAAP measures to their nearest measure prescribed by GAAP are provided below.

Calculation of Funds Flow

	Three months ended December 31		Year ended December 31	
(millions, except per unit amounts)	**2007**	**2006**	**2007**	**2006**
Cash flow from operating activities	**$ 311.7**	$ 261.1	**$ 1,241.8**	$ 1,106.3
Increase in non-cash working capital	**20.7**	32.9	**38.2**	43.6
Asset retirement expenditures	**14.8**	9.3	**51.5**	26.9
Funds flow	**$ 347.2**	$ 303.3	**$ 1,331.5**	$ 1,176.8
Basic per unit	**$ 1.44**	$ 1.23	**$ 5.56**	$ 5.86
Diluted per unit	**$ 1.43**	$ 1.22	**$ 5.51**	$ 5.78

Annual Financial Summary

	Year ended December 31		
(millions, except per unit amounts)	**2007**	**2006**	**2005**
Gross revenues (1)	**$ 2,461.8**	$ 2,100.9	$ 1,919.0
Funds flow	**1,331.5**	1,176.8	1,184.6
Basic per unit	**5.56**	5.86	7.28
Diluted per unit	**5.51**	5.78	7.14
Net income	**175.5**	665.6	577.2
Basic per unit	**0.73**	3.32	3.55
Diluted per unit	**0.73**	3.27	3.48
Total expenditures, net	**1,140.2**	577.9	456.7
Long-term debt at period-end	**1,943.2**	1,285.0	542.0
Distributions paid (2)	**976.0**	781.8	270.9
Dividends paid	**—**	—	17.5
Total assets	**$ 8,433.0**	$ 8,069.7	$ 3,967.1

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Includes distributions paid and reinvested in trust units under the distribution reinvestment plan.

Quarterly Financial Summary
(millions, except per unit and production amounts)

Three months ended	**Dec. 31 2007**	**Sept. 30 2007**	**June 30 2007**	**Mar. 31 2007**	**Dec. 31 2006**	**Sept. 30 2006**	**June 30 2006**	**Mar. 31 2006**
Gross revenues (1)	**$ 644.0**	$ 627.1	$ 608.3	$ 582.4	$ 578.5	$ 636.0	$ 452.5	$ 433.9
Funds flow	**347.2**	346.8	326.2	311.3	303.3	365.6	264.7	243.2
Basic per unit	**1.44**	1.44	1.37	1.31	1.23	1.55	1.59	1.49
Diluted per unit	**1.43**	1.43	1.35	1.30	1.22	1.53	1.56	1.47
Net income (loss)	**127.0**	137.4	(185.2)	96.3	122.9	177.8	220.5	144.4
Basic per unit	**0.53**	0.57	(0.77)	0.41	0.44	0.66	1.34	0.88
Diluted per unit	**0.52**	0.57	(0.77)	0.40	0.44	0.65	1.31	0.87
Distributions declared	**247.0**	245.0	243.5	242.4	241.5	240.7	167.6	162.0
Per unit	**$ 1.02**	$ 1.02	$ 1.02	$ 1.02	$ 1.02	$ 1.02	$ 1.02	$ 0.99
Production								
Liquids (bbls/d) (2)	**73,332**	72,783	70,923	71,716	70,819	69,215	48,599	52,226

Natural gas (mmcf/d)	**328.1**	315.4	334.1	340.6	354.6	359.1	267.9	266.9
Total (boe/d)	**128,024**	125,345	126,599	128,447	129,915	129,059	93,242	96,713

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Includes crude oil and natural gas liquids.

The major trend changes above are largely due to the acquisition of Petrofund Energy Trust ("Petrofund") on June 30, 2006 and the enactment of the Specified Investment Flow-Through tax legislation in the second quarter of 2007.

Canetic Acquisition

On January 11, 2008, the close of the acquisition of Canetic Resources Trust ("Canetic") was successfully completed. Canetic unitholders received 0.515 of a Penn West unit for each Canetic unit on a tax-deferred basis for Canadian and U.S. tax purposes plus a one-time special distribution of $0.09 per unit under the terms of the Combination Agreement.

Estimated Total Consideration	**(millions)**
124.3 million Penn West trust units issued	$ 3,572.5
Transaction costs	17.0
Bank debt	1,467.0
Convertible debentures	260.0
Working capital deficiency	153.0
Total	**$ 5,469.5**

Vault Acquisition

On January 10, 2008 the close of the acquisition of Vault Energy Trust ("Vault") was successfully completed. The acquisition was accomplished through a Plan of Arrangement wherein Vault unitholders received 0.14 of a Penn West trust unit for each Vault unit and all Vault exchangeable shares were exchanged for Penn West trust units based on the exchange ratio for Vault units at the effective date of the Plan of Arrangement. Subsequent to the close of the Vault acquisition, Penn West made its compulsory offer to redeem the Vault convertible debentures for cash at 101 percent of the principle amounts. On March 5, 2008, Penn West retired $23.8 million of the principle amount of the debentures for $24.5 million including the premium and accrued interest.

Estimated Total Consideration	**(millions)**
5.6 million Penn West trust units issued	$ 157.9
Transaction costs	5.0
Bank debt	88.8
Convertible debentures	100.9
Working capital deficiency	33.4
Total	**$ 386.0**

The New Alberta Royalty Framework

On October 25, 2007, the Government of Alberta (the "Government") released its new royalty framework which is to become effective January 1, 2009. The new framework maintains or continues certain programs that are important to Penn West:

- Conventional production from oil sands leases will maintain oil sands administrative status which benefits our Peace River Oil Sands project due to the reduced royalty rates;

- Enhanced Oil Recovery ("EOR") and Innovative Energy Technology incentive programs will continue. Penn West has significant inventories of legacy light oil interests amenable to EOR and interests in CO_2 EOR producing and other CO_2 pilot projects; and

- Otherwise Flared Solution Gas Waiver Program will continue, which supports our long-standing environmental operating and asset optimization objectives.

On conventional production, the Government confirmed that its new royalty framework will be sensitive to well productivity and commodity prices at slightly higher thresholds than the September 18, 2007 proposals of the Alberta Royalty Review Panel. Penn West, as the largest energy trust in North America, has a diversity of play types across the Western Canada Sedimentary Basin. Approximately 60 percent of our production is from Alberta Crown leases and our historical asset strategies have favoured mature assets. We are currently assessing the impact that the new royalty framework will have on our conventional capital allocations for 2008 and beyond. We currently expect that our conventional producing oil and natural gas strategies and business plans will only be minimally affected at current commodity prices and at our current asset mix.

In January 2008, ministers of the Government of Alberta publically stated that a possible re-review of the new Alberta Royalty Framework could occur, with the objective of avoiding "unintended consequences" such as disincentives to drill certain types of wells; however, no details have been formally announced.

Enactment of the Tax on Income Trusts

On June 12, 2007, the federal legislation (Bill C-52) implementing the new tax on publicly traded income trusts and limited partnerships (the "SIFT tax"), referred to as "Specified Investment Flow-Through" ("SIFT") entities received third reading in the House of Commons and on June 22, 2007, the Bill received Royal Assent.

For SIFTs in existence on October 31, 2006 including Penn West, the SIFT tax will be effective in 2011 unless certain rules related to "undue expansion" are not adhered to. Under the guidance provided, with the recent close of Vault and Canetic and along with other transactions, we can increase our equity by approximately $15 billion between now and 2011 without prematurely triggering the SIFT tax.

Under the SIFT tax, distributions from certain types of income will not be deductible for income tax purposes by SIFTs in 2011, and thereafter, and any resultant trust level taxable income will be taxed at approximately the corporate income tax rate. The SIFT rate was initially proposed at 31.5 percent; however, on October 30, 2007, the Government of Canada, in its Mini-Budget (Bill C-28), proposed reductions to the general corporate tax rate, thereby reducing the SIFT rate to 29.5 percent in 2011 and 28.0 percent in 2012 and later. On December 14, 2007 Bill C-28 received Royal Assent, resulting in a reduction to the SIFT tax rate as it becomes effective in 2011, and lowering the rate at which any corporate income taxes will be paid in Penn West's operating entities. As the Trust currently has a significant tax pool base and expects to increase its tax pool base until 2011, it is expected that the Trust could shelter its taxable income for a period after the effective date of the SIFT tax. Distributions of this nature would not be currently taxable to unitholders as they would represent a return of capital that would continue to be an adjustment to a unitholder's adjusted cost base of trust units. Distributions from income subject to the SIFT tax will be considered taxable dividends to unitholders and will generally be eligible for the dividend tax credit. The SIFT tax was not intended to adversely affect the after-tax yield of Canadian investors who hold Penn West units in a non-tax deferred account.

For accounting purposes, the SIFT tax charge during the second quarter of 2007 was $325.5 million reflecting the current estimate of the temporary differences between the book and tax basis of assets and liabilities expected to be remaining in the Trust in 2011. The majority of the temporary differences at the Penn West Trust level resulted from the acquisition of Petrofund on June 30, 2006.

Penn West Petroleum Ltd.'s Board of Directors and management are continuously monitoring the impact of this tax on our business strategies. We expect future technical interpretations and details will further clarify the legislation. At the present time, Penn West believes some or all of the following actions will or could result in the future due to the SIFT tax:

- If structural or other similar changes are not made, the distribution yield net of the SIFT tax in 2011 and beyond to taxable Canadian investors will remain approximately the same; however, the distribution yield to tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) would fall by an estimated 29.5 percent in 2011 and 28.0 percent in 2012 and beyond. For U.S. investors, the distribution yield net of the SIFT and withholding taxes would fall by an estimated 25.1 percent in 2011 and 23.8 percent in 2012 and beyond;

- A portion of Penn West's funds flow could be required for the payment of the SIFT tax, or other forms of tax, and would not be available for distribution or reinvestment;

- Penn West could convert to a corporate structure with yield in the form of dividends to facilitate investing a higher proportion or all of its funds flow in exploration and development projects. Such a conversion could result in the reduction, or the elimination, of the current distribution program in favour of higher capital investment and/or a dividend payment program; and

- Penn West might determine that it is more economic to remain in the trust structure, at least for a period of time, and shelter its taxable income using tax pools and pay all or a portion of its distributions on a return of capital basis, likely at a lower payout ratio. Further, as the SIFT tax rate exceeds the corporate income tax rate that would be applicable to Penn West, the tax strategy might involve paying some corporate tax resulting in all or a portion of those distributions being paid on a return of capital basis at a lower payout ratio.

The Trust continues to review all organizational structures and alternatives to minimize the impact of the SIFT tax on its unitholders. While there can be no assurance that the negative effect of the tax can be minimized or eliminated, Penn West and its advisors will continue to work diligently on these issues.

On February 26, 2008, the Government of Canada, in its Federal Budget, announced changes to the SIFT tax rules. The provincial component of the SIFT tax will be based on the provincial rates where the SIFT has a permanent establishment rather than using a 13 percent flat rate. As Penn West currently has its permanent establishment in the Province of Alberta, its combined SIFT tax rate applicable in 2012 is expected to fall from 28 percent to 25 percent.

Business Environment

The current business environment reflects high oil prices offset by weak natural gas prices, a strong Canadian dollar relative to the U.S. dollar, volatile capital markets due to turmoil in debt capital markets caused by asset-backed commercial paper and sub-prime mortgage issues and low interest rates by historical standards, offset by significantly higher credit spreads on corporate debt.

Continuing demand for commodities including crude oil from growing economies such as China and India, increasing oil consumption in many of the oil exporting countries and continuing political instability in parts of the world resulted in oil prices remaining strong in 2007. The price of West Texas Intermediate ("WTI"), the primary benchmark for light crude oil prices, averaged US$72.34 per barrel in 2007, up by approximately nine percent from 2006.

Heavy oil differentials widened slightly in 2007, a result of continued refinery upsets throughout the year. The Canadian Bow River differential to WTI widened by eight percent from 2006.

AECO natural gas prices weakened in 2007, decreasing by five percent to $6.60 per mcf from $6.98 per mcf in 2006. Weak natural gas prices

reflected record North American storage levels resulting from warmer than average North American temperatures coupled with record liquefied natural gas ("LNG") imports driven by warmer than average weather in other parts of the world. Recently, the outlook for natural gas prices has begun to improve as global demand for natural gas has continued to outpace supply due to colder weather resulting in lower North American LNG deliveries and leading to more balanced supply/demand fundamentals.

Lower natural gas prices and a strengthening of the Canadian dollar relative to the U.S. dollar continued to partially 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 reduced Canadian dollar-denominated oil prices. The average exchange rate increased from CAD$1.00 equals US$0.8882 in 2006 to CAD$1.00 equals US$0.9300 in 2007 and is currently approximately at parity.

Royalties came under scrutiny by the Alberta government in 2007 leading to the announcement of the new royalty rate framework for the province with an effective date of January 1, 2009. Other provinces have maintained current royalty structures; however, future changes, both positive and/or negative in nature, may occur.

Operating cost initiatives continue to be a focus of Penn West. During 2007, the industry encountered a slow-down in drilling activity primarily due to low natural gas prices and uncertainties resulting from the Alberta royalty review. Penn West experienced only modest increases in operating costs as a result of these factors.

We have an experienced management team and strong technical staff who are committed to exploiting our assets along with realizing operational efficiencies from our economies of scale. Over the past two years, we have completed significant acquisitions including Canetic, Petrofund and Vault, all adding production and reserves throughout the Western Canada Sedimentary Basin and elsewhere. We are now the largest conventional oil and natural gas trust in North America, with a dominant position in Canada's legacy light oil pools. These conventional opportunities combined with our unconventional resource plays including our Peace River Oil Sands project, coal bed methane, shale gas and enhanced oil recovery opportunities create the diversity and the flexibility that will help us to adjust to changing economic, political and environmental conditions.

Penn West strives to generate and preserve unitholder value by:

- Continuing the development of our high-quality assets, with a balance between low-risk, cost efficient resource plays and further development of our unconventional opportunities such as our Peace River Oil Sands project and CO_2 enhanced oil recovery projects;
- Maintaining a stable distribution profile through active risk management activities, maintaining and optimizing our production infrastructure, further consolidating our core asset areas and exploiting opportunities availed by our undeveloped land position;
- Pursuing strategic or accretive acquisitions both domestically and internationally to further expand our already significant inventory of assets; and
- Maintaining our strong financial position and balance sheet and operating with financial discipline.

Unitholder Value Measures

	Year ended December 31		
	2007	2006	2005
Funds flow per unit	**$ 5.56**	$ 5.86	$ 7.28
Distributions per unit	**$ 4.08**	$ 4.05	$ 1.97
Dividends per unit	**$ —**	$ —	$ 0.07
Ratio of year-end bank debt to annual funds flow	**1.5**	1.1	0.5

Penn West maintained a distribution of $0.34 per unit per month throughout 2007 and had continued that level since the rate was increased in February 2006. Increases in the bank debt to funds flow ratio were primarily due to property acquisitions during 2007 that led to increased debt levels.

Performance Indicators

	Year ended December 31		
	2007	2006	2005
Return on capital employed (1)	**8.9%**	12.8%	17.0%
Total assets (millions)	**$ 8,433**	$ 8,070	$ 3,967
Return on equity (2)	**3.6%**	18.1%	28.3%

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

During 2007, pre-tax net income was affected by the $201.6 million unrealized loss on risk management activities in 2007. Further, in the second quarter of 2007, the enactment of the SIFT tax led to a $325.5 million non-cash, future income tax charge during the period. During the fourth quarter of 2007, the Government of Canada announced rate reductions that led to a $106.4 million reduction in the period. If neither the SIFT tax nor the tax rate reductions had been enacted in 2007, return on capital employed and return on equity would have been 13.1 percent and 8.1 percent respectively.

Results Of Operations

Production

Daily production	Three months ended December 31 2007	2006	% change	Year ended December 31 2007	2006	% change
Natural gas (mmcf/d)	**328.1**	354.6	(7)	**329.4**	312.5	5
Light oil and NGL (bbls/d)	**51,070**	48,233	6	**50,175**	39,514	27
Conventional heavy oil (bbls/d)	**22,262**	22,586	(1)	**22,019**	20,776	6
Total production (boe/d) (1)	**128,024**	129,915	(1)	**127,098**	112,369	13

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

Production in the fourth quarter of 2007 exceeded the 125,345 boe per day produced in the third quarter of 2007 due primarily to the resumption of production at our 100 percent owned Wildboy natural gas plant in November 2007. The plant was running at only partial capacity after a fire at the adjoining tank farm in mid-May of 2007. We expect that our business interruption insurance will cover the majority of the lost funds flow, excluding the deductible portion.

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. In the fourth quarter of 2007, crude oil and NGL production averaged 73,332 barrels per day (57 percent of production) and natural gas production averaged 328.1 mmcf per day (43 percent of production).

We drilled 43 net wells in the fourth quarter of 2007, mainly in the Central and Plains areas, compared to 52 in the same period of 2006.

Commodity Markets

Natural Gas

North American natural gas prices remained weak in the fourth quarter of 2007, particularly compared to oil prices. Natural gas storage levels continued to grow throughout the fall reaching record levels to offset the increased demand due to the onset of winter. Spot natural gas prices at AECO in the fourth quarter increased to $6.00 per mcf or approximately seven percent over the prior quarter. Penn West's realized price averaged $6.54 per mcf, including gains from commodity contracts.

Crude Oil

WTI oil prices strengthened in the fourth quarter of 2007, with continued concern over supply and inventory levels coupled with ongoing geo-political concerns. The crude oil market has been extremely volatile in recent months as demand appeared to remain impervious to price. As the Canadian dollar strengthened relative to the U.S. dollar, Edmonton par oil prices traded lower relative to WTI prices through the quarter. Both heavy and sour Canadian oil differentials to the Edmonton par light oil price widened over the third quarter of 2007. Bow River differential to Edmonton averaged $29.50 per barrel compared to $24.60 in the previous quarter due primarily to lower seasonal demand and scheduled refinery turnarounds in the quarter. Penn West's average price for liquids, including realized losses from commodity contracts, was $65.71 per barrel.

Average Sales Prices Received

	Three months ended December 31 2007	2006	% change	Year ended December 31 2007	2006	% change
Natural gas (per mcf)	**$ 6.34**	$ 6.97	(9)	**$ 6.85**	$ 6.75	1
Risk management (per mcf)	**0.20**	0.56	(64)	**0.17**	0.72	(76)
Natural gas net (per mcf)	**6.54**	7.53	(13)	**7.02**	7.47	(6)
Light oil and NGL (per bbl)	**76.99**	57.43	34	**68.75**	65.02	6
Risk management (per bbl)	**(3.87)**	0.01	—	**(0.97)**	(1.00)	(3)
Light oil and NGL (per bbl)	**73.12**	57.44	27	**67.78**	64.02	6
Conventional heavy oil (per bbl)	**48.69**	37.57	30	**45.26**	43.07	5
Weighted average (per boe)	**55.44**	46.88	18	**52.73**	49.58	6
Risk management (per boe)	**(1.02)**	1.53	(167)	**0.06**	1.64	(96)
Weighted average net (per boe)	**$ 54.42**	$ 48.41	12	**$ 52.79**	$ 51.22	3

Netbacks

	Three months ended December 31 2007	2006	% change	Year ended December 31 2007	2006	% change

Natural gas												
Production (mmcf/day)		**328.1**		354.6	(7)		**329.4**		312.5	5
Operating netback (per mcf):												
Sales price	**$**	**6.34**	$	6.97	(9)	**$**	**6.85**	$	6.75	1
Risk management (gain) (2)		**(0.20)**		(0.56)	(64)		**(0.17)**		(0.72)	(76)
Royalties		**1.34**		1.63	(18)		**1.48**		1.53	(3)
Operating costs		**1.17**		1.04	13		**1.12**		0.99	13
Transportation		**0.21**		0.18	17		**0.20**		0.21	(5)
Netback	**$**	**3.82**	$	4.68	(18)	**$**	**4.22**	$	4.74	(11)
Light oil and NGL										
Production (bbls/day)		**51,070**		48,233	6		**50,175**		39,514	27
Operating netback (per bbl):										
Sales price	**$**	**76.99**	$	57.43	34	**$**	**68.75**	$	65.02	6
Risk management loss (gain) (2)		**3.87**		(0.01)	—		**0.97**		1.00	(3)
Royalties		**13.24**		10.55	26		**11.94**		10.87	10
Operating costs		**15.55**		15.36	1		**15.29**		15.80	(3)
Netback	**$**	**44.33**	$	31.53	41	**$**	**40.55**	$	37.35	9
Conventional heavy oil										
Production (bbls/day)		**22,262**		22,586	(1)		**22,019**		20,776	6
Operating netback (per bbl):										
Sales price	**$**	**48.69**	$	37.57	30	**$**	**45.26**	$	43.07	5
Royalties		**7.18**		6.46	11		**6.79**		7.47	(9)
Operating costs		**12.32**		11.88	4		**12.18**		11.22	9
Transportation		**0.06**		0.07	(14)		**0.07**		0.07	—
Netback	**$**	**29.13**	$	19.16	52	**$**	**26.22**	$	24.31	8
Total liquids										
Production (bbls/day)		**73,332**		70,819	4		**72,194**		60,290	20
Operating netback (per bbl):										
Sales price	**$**	**68.40**	$	51.09	34	**$**	**61.59**	$	57.46	7
Risk management loss (gain) (2)		**2.69**		(0.01)	—		**0.67**		0.66	2
Royalties		**11.40**		9.24	23		**10.37**		9.69	7
Operating costs		**14.57**		14.25	2		**14.34**		14.22	1
Transportation		**0.02**		0.02	—		**0.02**		0.03	(33)
Netback	**$**	**39.72**	$	27.59	44	**$**	**36.19**	$	32.86	10
Combined totals										
Production (boe/day) (1)		**128,024**		129,915	(1)		**127,098**		112,369	13
Operating netback (per boe):										
Sales price	**$**	**55.44**	$	46.88	18	**$**	**52.73**	$	49.58	6
Risk management loss (gain) (2)		**1.02**		(1.53)	(167)		**(0.06)**		(1.64)	(96)
Royalties		**9.97**		9.48	5		**9.72**		9.46	3
Operating costs		**11.35**		10.61	7		**11.04**		10.39	6
Transportation		**0.56**		0.51	10		**0.52**		0.60	(13)
Netback	**$**	**32.54**	$	27.81	17	**$**	**31.51**	$	30.77	2

(1) Barrels of oil equivalent (boe) are based on six mcf of natural gas being equal to one barrel of oil (6:1).
(2) Realized component of risk management activities related to oil and natural gas prices.

Production Revenues

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

	Year ended December 31		
(millions)	**2007**	**2006**	**2005**
Natural gas	**$ 856.6**	$ 850.9	$ 918.2
Light oil and NGL	**1,241.4**	923.4	757.0
Conventional heavy oil	**363.8**	326.6	243.8
Gross revenues (1)	**$ 2,461.8**	$ 2,100.9	$ 1,919.0

(1) Gross revenues include realized gains and losses on commodity contracts.

Increases (Decreases) in Production Revenues

(millions)	
Gross revenues – 2006	$ 2,100.9
Increase in light oil and NGL production	249.2

Increase in light oil and NGL prices (including realized risk management)	68.9
Increase in conventional heavy oil production	19.5
Increase in conventional heavy oil prices	17.6
Increase in natural gas production	46.1
Decrease in natural gas prices (including realized risk management)	(40.4)
Gross revenues – 2007	$ 2,461.8

In the fourth quarter of 2007 gross revenues increased by 11 percent to $644.0 million from $578.5 million in 2006. This was primarily due to a 34 percent increase in light oil and NGL sales prices to $76.99 per bbl in 2007 from $57.43 per bbl in 2006 and a 30 percent increase in conventional heavy oil sales price to $48.69 per bbl in 2007 from $37.57 per bbl in 2006.

Royalties

	Year ended December 31		
	2007	**2006**	**2005**
Royalties (millions)	**$ 450.8**	$ 388.0	$ 369.7
Average royalty rate (%)	**18%**	18%	19%
Per boe	**$ 9.72**	$ 9.46	$ 10.15

Expenses

	Year ended December 31		
(millions)	**2007**	**2006**	**2005**
Operating	**$ 512.2**	$ 426.3	$ 327.4
Transportation	**24.1**	24.5	22.7
Financing	**92.4**	49.3	23.2
Unit-based compensation	**$ 20.5**	$ 11.3	$ 77.2

	Year ended December 31		
(per boe)	**2007**	**2006**	**2005**
Operating	**$ 11.04**	$ 10.39	$ 8.99
Transportation	**0.52**	0.60	0.62
Financing	**2.00**	1.20	0.63
Unit-based compensation	**$ 0.44**	$ 0.27	$ 2.12

Operating

Penn West continued all of its initiatives to limit increases to operating costs. Over the past two years, operating cost escalation occurred industry-wide due to strong demand for skilled labour and oilfield services, particularly drilling and oilfield service rigs. Penn West's modest increases in operating costs per barrel of oil equivalent were generally due to a higher proportion of liquids production in 2007 than in the comparative 2006 periods. Currently, with the low natural gas price and the recent Alberta royalty recommendations, we are experiencing a slow-down in industry activity that is expected to alleviate some of the high demand for oilfield services in the near future. The addition of the Petrofund assets effective July 1, 2006, with higher operating costs than the Penn West assets, also contributed to the increase.

During the fourth quarter of 2007, operating costs increased by six percent to $135.1 million from $127.7 million in the same period of 2006, due to industry-wide cost escalations.

A realized gain of $11.0 million (2006 – $17.3 million) on our electricity contracts was included in operating costs for the year.

Financing

Penn West Petroleum Ltd. ("the Company") closed the placement of US$475 million of notes on May 31, 2007. The interest rates on the notes are fixed at 5.68 to 6.05 percent for terms of 8 to 15 years and average 5.8 percent. During September 2007, the Company entered into foreign exchange contracts to fix the repayment (in Canadian dollars) on US$250 million at an exchange rate of approximately one Canadian dollar at par with one U.S. dollar. In addition, the Company has swaps on $100 million of bank debt that fix the interest rate at approximately 4.36 percent until March 2008 and on $100 million of bank debt that fix the interest rate at approximately 4.26 percent until November 2010. The interest rate on the balance of the Company's long-term debt is currently based on short-term, floating interest rate debt instruments.

In the fourth quarter of 2007, Penn West incurred $27.2 million of financing charges compared to $17.8 million in the same period of 2006 due to increased debt levels.

The 2007 increase in interest expense resulted from both an increase in the average outstanding debt balance and increases in interest rates over 2006. The U.S. notes contain slightly higher fixed interest rates than the Company was subject to under its syndicated credit facility using short-term money market instruments. Penn West believes the long-term nature and the fixed interest rates inherent in the notes are beneficial for a portion of its capital structure. The increased average loan balance was principally due to property acquisitions in 2007.

Unit-Based Compensation

Unit-based compensation expense related to Penn West's Trust Unit Rights Incentive 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 amortized over the remaining vesting periods on a straight-line basis. The unit-based compensation expense was $5.5 million for the three months ended December 31, 2007, of which $1.5 million

was charged to operating expense and $4.0 million was charged to general and administrative expense (2006 – $3.1 million, $0.8 million and $2.3 million, respectively). The amount per boe increased in 2007 due to additional options granted in the period.

General and Administrative Expenses

	Year ended December 31		
	2007	2006	2005
Gross (millions)	**$ 83.3**	$ 62.0	$ 45.0
Per boe	**1.80**	1.51	1.24
Net (millions)	**50.8**	36.0	23.1
Per boe	**$ 1.10**	$ 0.88	$ 0.64

The workplace environment continues to be highly competitive in hiring, compensating and retaining employees and consultants. Professional staff, particularly those with experience and strong technical skills, continue to be in high demand, leading to increased compensation costs. Additional regulatory compliance activities have also contributed to increased costs.

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

	Year ended December 31		
(millions, except per boe amounts)	2007	2006	2005
Depletion of oil and natural gas assets	**$ 867.4**	$ 635.0	$ 416.5
Accretion of asset retirement obligation (1)	**29.3**	19.7	21.1
Total DD&A	**$ 896.7**	$ 654.7	$ 437.6
DD&A expense per boe	**$ 19.33**	$ 15.96	$ 12.01

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

DD&A expense in 2007 was higher than in 2006 due to a full year of production from the Petrofund assets and a higher depletion rate as a result of the Petrofund acquisition, which closed in June 30, 2006. Penn West accounted for the acquisition as a purchase of Petrofund with the purchase price allocated to the fair value of net identifiable assets acquired. The purchase price allocation to oil and natural gas assets at fair value significantly increased our consolidated depletion base per unit. Preliminary estimates for 2008 indicate the 2008 DD&A rate will further increase due to the Vault and Canetic acquisitions.

Taxes

	Year ended December 31		
(millions)	2007	2006	2005
Current income	**$ —**	$ —	$ 54.1
Future income expense (reduction)	**75.4**	(106.2)	(1.1)
	$ 75.4	$ (106.2)	$ 53.0

Temporary differences at the Trust level, or differences between book and tax basis of the assets and liabilities, were previously not recognized under GAAP as future income taxes because the Trust was required to distribute all of its taxable income under the terms of its Trust Indenture. Under the SIFT legislation, in 2011 and beyond, as distributions will no longer be tax deductible, the Trust will not be able to make distributions to reduce its taxable income and thus is no longer considered to be exempt from income taxes for accounting purposes.

During the second quarter of 2007, a $325.5 million charge was recorded due to the enactment of the SIFT tax legislation during the period. The future income tax liability was increased to reflect the current temporary differences expected to be remaining at the Trust level in 2011 using the then effective SIFT tax rate of 31.5 percent. On October 30, 2007, the Government of Canada proposed rate reductions which were enacted in Bill C-28 on December 14, 2007 lowering the SIFT tax rate to 29.5 percent in 2011 and to 28.0 percent for 2012 and beyond and reducing future corporate income tax rates by an additional 3.5 percent. During the fourth quarter of 2007, a $106.4 million future income tax reduction was recorded to reflect these substantively enacted tax rates.

On February 26, 2008, the Government of Canada, in its Federal Budget, announced changes to the SIFT tax rules. The provincial component of the SIFT tax will be based on the provincial rates where the SIFT has a permanent establishment rather than using a 13 percent flat rate. For Penn West, the SIFT tax rate applicable in 2012 is expected to fall from 28 percent to 25 percent. As the tax rate change has not been substantively enacted, no future income tax rate benefit has been recorded in the financial statements.

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 income taxes in the operating entities. With the new legislation, such amounts transferred to the Trust could be taxable beginning in 2011 as distributions will no longer be deductible by the Trust for income tax purposes. At that time, Penn West could claim on its tax pools and pay all or a portion of its distributions on a return of capital basis. Such distributions would not be immediately taxable to investors; they would generally reduce the adjusted cost base of units held by investors, however such distributions would potentially be at a lower payout ratio.

The new legislation is not currently expected to directly affect our funds flow levels and distribution policies until 2011 at the earliest.

The estimate of future income taxes is based on the current tax status of the Trust. Future events, which could materially affect future income taxes such as acquisitions and dispositions and modifications to the distribution policy, are not reflected under Canadian GAAP until the events occur and the related legal requirements have been fulfilled. As a result, future changes to the tax legislation could lead to a material change in the recorded amount of future income taxes.

Tax Pools

	As at December 31		
(millions)	**2007**	**2006**	**2005**
Undepreciated capital cost (UCC)	**$ 826.2**	$ 788.3	$ 519.0
Canadian oil and gas property expense (COGPE)	**1,308.6**	1,091.0	707.6
Canadian development expense (CDE)	**413.7**	428.8	329.8
Non-capital losses	**697.4**	106.1	—
Total tax pools	**$ 3,245.9**	$ 2,414.2	$ 1,556.4

The increase in the 2007 tax pools reflects capital spending and income transfers to the Trust throughout the year. The tax pool figures are net of income deferred in operating partnerships.

Foreign Exchange

In 2007, the Trust had U.S.-dollar-denominated debt totalling $475 million compared to nil in 2006. The Trust recorded unrealized foreign exchange gains of $38.2 million in 2007 related to the outstanding U.S. notes. No gains were realized on these contracts in 2007 as no amounts were settled or converted to Canadian dollars during the year.

Funds Flow and Net Income

	Three months ended December 31			Year ended December 31		
	2007	**2006**	**% change**	**2007**	**2006**	**% change**
Funds flow (1) (millions)	**$ 347.2**	$ 303.3	14	**$ 1,331.5**	$ 1,176.8	13
Basic per unit	**1.44**	1.23	17	**5.56**	5.86	(5)
Diluted per unit	**1.43**	1.22	17	**5.51**	5.78	(5)
Net income (millions)	**127.0**	122.9	3	**175.5**	665.6	(74)
Basic per unit	**0.53**	0.44	20	**0.73**	3.32	(78)
Diluted per unit	**$ 0.52**	$ 0.44	18	**$ 0.73**	$ 3.27	(78)

(1) Funds flow is a non-GAAP measure. See “Calculation of Funds Flow”.

Funds flow realized in 2007 increased from the comparable 2006 period due to higher production volumes resulting from the Petrofund acquisition, partially offset by higher operating and financing costs.

In the absence of the $325.5 million non-cash charge taken in the second quarter of 2007 to reflect the enactment of the SIFT tax and the $106.4 million rate recovery received in the fourth quarter of 2007, net income for 2007 would have been $394.6 million.

	Year ended December 31					
	2007		**2006**		**2005**	
	$/boe	**%**	**$/boe**	**%**	**$/boe**	**%**
Oil and natural gas revenues (1)	**$ 53.08**	**100.0**	$ 51.22	100.0	$ 52.68	100.0
Net royalties	**(9.72)**	**(18.3)**	(9.46)	(18.4)	(10.15)	(19.3)
Operating expenses (2)	**(11.04)**	**(20.8)**	(10.39)	(20.3)	(8.99)	(17.1)
Transportation	**(0.52)**	**(1.0)**	(0.60)	(1.2)	(0.62)	(1.1)
Net operating income	**31.80**	**59.9**	30.77	60.1	32.92	62.5
General and administrative expenses	**(1.10)**	**(2.0)**	(0.88)	(1.7)	(0.64)	(1.2)
Interest	**(2.00)**	**(3.8)**	(1.20)	(2.3)	(0.63)	(1.2)
Realized foreign exchange gain	**—**	**—**	—	—	2.35	4.4
Current taxes	**—**	**—**	—	—	(1.48)	(2.8)
Funds flow	**28.70**	**54.1**	28.69	56.0	32.52	61.7
Unrealized foreign exchange gain (loss)	**0.82**	**1.5**	—	—	(2.48)	(4.7)
Unit-based compensation	**(0.44)**	**(0.8)**	(0.27)	(0.5)	(2.12)	(4.0)
Risk management activities (3)	**(4.35)**	**(8.2)**	1.18	2.3	(0.09)	(0.2)
Depletion, depreciation and accretion	**(19.33)**	**(36.4)**	(15.96)	(31.2)	(12.01)	(22.8)
Future income taxes	**(1.63)**	**(3.0)**	2.59	5.1	0.03	—
Net income	**$ 3.77**	**(7.2)**	$ 16.23	31.7	$ 15.85	30.0

(1) Gross revenues include realized gains and losses on commodity contracts.

(2) Operating expenses include realized gains on electricity swaps.
(3) Risk management activities relate to the unrealized gain and losses on derivative instruments.

Goodwill

The goodwill balance of $652.0 million resulted from the acquisition of Petrofund in June 2006. The Trust has determined that there was no goodwill impairment as of December 31, 2007.

Capital Expenditures

	Three months ended December 31		Year ended December 31	
(millions)	**2007**	**2006**	**2007**	**2006**
Property acquisitions (dispositions), net	**$ 19.7**	$ 10.9	**$ 421.7**	$ 5.6
Land acquisition and retention	**0.8**	0.8	**30.2**	19.8
Drilling and completions	**96.1**	86.1	**367.2**	317.4
Facilities and well equipping	**73.0**	57.9	**254.1**	224.6
Geological and geophysical	**0.5**	1.0	**10.2**	3.6
CO_2 pilot costs	**9.8**	1.1	**19.8**	3.7
Administrative	**10.8**	1.6	**15.8**	3.2
Capital expenditures	**210.7**	159.4	**1,119.0**	577.9
Business combination	**—**	—	**21.2**	3,323.3
Total expenditures	**$ 210.7**	$ 159.4	**$ 1,140.2**	$ 3,901.2

We drilled 43 net wells in the fourth quarter of 2007, resulting in 25 net oil wells, nine net natural gas wells and nine stratigraphic wells with a success rate of 99 percent. Our drilling activities were focused primarily in the Central and Plains areas.

On June 30, 2006, we closed the acquisition of Petrofund. The fair value of the oil and natural 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.

The acquisition of C1 Energy Ltd (“C1”) for a total cost of approximately $21.2 million closed during the third quarter of 2007 and was accounted for as a purchase. Also, during 2007, we completed a number of other minor property acquisitions.

In addition to the above noted capital expenditures, for the year ended December 31, 2007, $5.1 million was capitalized for future income taxes on acquisitions to reflect the acquisitions with a different tax basis than the purchase prices and $96.6 million was capitalized for additions to asset retirement obligations to reflect the additional retirement obligations from both capital programs and net acquisitions.

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.

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, foreign currency and environmental risk. From time to time, we attempt to minimize exposure to a portion of these risks by using financial instruments and by other means.

Commodity Price Risk

Commodity price fluctuations are among the Trust’s most significant exposures. 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 including weather, storage levels and LNG imports, influence natural gas prices. In accordance with policies approved by our Board of Directors, 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 contracts, please refer to “Financial Instruments” later in this MD&A or our website at www.pennwest.com which includes all current contracts including those assumed in the Canetic and Vault acquisitions which closed in January 2008.

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 are 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.

In September 2007, we entered into foreign exchange contracts to fix the foreign exchange rate on the future repayment of US$250 million of U.S.-dollar-denominated private notes at an exchange rate of approximately one Canadian dollar equalling one U.S. dollar. At December 31,

2007, we had U.S.-dollar-denominated debt with a face value of US$225 million outstanding on which the repayment of principal amount in Canadian dollars is not fixed.

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 currently maintain a portion of our debt in floating-rate bank facilities, which results in exposure to fluctuations in short-term interest rates that have for a number of years been lower than longer-term rates. From time to time, we may increase the certainty of our future interest rates by entering fixed interest rate debt instruments or by using financial instruments to swap floating interest rates for fixed rates or to collar interest rates.

In April 2006, we entered into interest rate swaps for two years at 4.36 percent on $100 million of bank debt and in November 2007 we entered into interest rate swaps for three years at 4.26 percent on $100 million of bank debt, both of which fixed the interest rates for the stated period of time. We closed the placement of notes totalling US$475 million on May 31, 2007 that bear fixed interest rates at an average rate of 5.8 percent for an average term of 10.1 years.

Liquidity and Capital Resources

Capitalization

	Year ended December 31					
(millions)	**2007**		**2006**		**2005**	
Trust units issued, at market	**$ 6,270**	**74.0**	$ 8,435	86.0	$ 6,203	90.5
Bank loans and notes	**1,943**	**22.9**	1,285	13.1	542	7.9
Working capital deficiency (1)	**266**	**3.1**	86	0.9	127	1.6
Total enterprise value	**$ 8,479**	**100.0**	$ 9,806	100.0	$ 6,872	100.0

(1) Current assets minus current liabilities.

During 2007, we paid total distributions, including those funded by the distribution reinvestment plan, of $976.0 million, compared to distributions of $781.8 million in 2006. This increase was due to the increase in the distribution rate from $0.31 per unit, per month in February 2006, to the rate since that time of $0.34 per unit, per month, and the 70.7 million additional units issued as consideration for Petrofund in June 2006.

Long-term debt at December 31, 2007 was $1,943.2 million compared to $1,285.0 million at December 31, 2006. In January 2008, our wholly owned subsidiary, Penn West Petroleum Ltd., amended its unsecured, revolving syndicated credit facility to an aggregate borrowing limit of $4.0 billion expiring on January 11, 2011, to enable the cancellation of the credit facilities of Canetic and Vault. The facility is made up of two revolving tranches; tranche one of the facility is $3.25 billion and extendible, and tranche two is $750 million and non-extendible. Stamping fees range from 55 - 110 basis points and standby fees range from 11.0 - 22.5 basis points depending on our ratio of bank debt to income before interest, taxes and depreciation and depletion (“EBITDA”). The syndicated facility expiry date on both tranches is January 11, 2011.

On May 31, 2007, the Company closed an offering of notes issued on a private placement basis in the United States, with an aggregate principal amount of US$475 million. The Company used the proceeds of the notes to repay a portion of its outstanding bank debt under its credit facilities. The notes mature in 8 to 15 years and bear interest at rates between 5.68 and 6.05 percent.

On December 31, 2007, the Company was in compliance with all of the financial covenants under its syndicated credit facility that closed on January 10, 2008. The financial covenants under the syndicated credit facility, which include the unaudited pro forma Canetic, Vault and Titan Exploration Ltd. (“Titan”) historical results, are as follows:

- Consolidated senior 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 senior debt to total trust capitalization shall not exceed 50 percent except in certain circumstances and shall not exceed 55 percent.

At December 31, 2007, the pro forma consolidated senior and total debt to EBITDA ratios were 1.5:1 and 1.6:1 respectively, and the consolidated senior debt to capitalization ratio was 29.5 percent.

On December 31, 2007, the Company was in compliance with the financial covenant pursuant to the notes, which is that consolidated total debt to consolidated total capitalization is not to exceed 55 percent except in certain circumstances where it is not to exceed 60 percent.

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 current 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, plus 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. Penn West has never declared such a distribution and, at the current time, it forecasts that such a special distribution will not be required in 2008.

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 will be 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 funds flow would be required to fund our environmental expenditures.

Standardized Distributable Cash

Prior to the recent guidance from accounting and regulatory standard setters on the disclosure of distributable cash, Penn West's disclosures regarding distributable cash to its investors focused on statistics including a reconciliation of cash flow from operating activities to distributions declared and distributions declared as a percentage of cash flow from operating activities and net income. The Canadian Institute of Chartered Accountants ("CICA") issued the Interpretive Release "Standardized Distributable Cash in Income Trusts and Other Flow-Through Entities" in July 2007, which provided further guidance. In the guidance, sustainability concepts are discussed and standardized distributable cash 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 an entity's ability to pay distributions or maintain productive capacity.

	Three months ended December 31		Year ended December 31	
(millions, except per unit amounts, ratios and percentages)	**2007**	**2006**	**2007**	**2006**
Cash flow from operating activities	**$ 311.7**	$ 261.1	**$ 1,241.8**	$ 1,106.3
Productive capacity maintenance (1)	**(191.0)**	(148.5)	**(697.3)**	(572.3)
Standardized distributable cash	**120.7**	112.6	**544.5**	534.0
Proceeds from the issue of trust units (2)	**50.2**	31.3	**163.1**	118.6
Debt and working capital changes	**76.1**	97.6	**270.3**	159.2
Cash distributions declared	**$ 247.0**	$ 241.5	**$ 977.9**	$ 811.8
Accumulated cash distributions, beginning	**1,864.2**	891.8	**1,133.3**	321.5
Accumulated cash distributions, ending	**$ 2,111.2**	$ 1,133.3	**$ 2,111.2**	$ 1,133.3
Standardized distributable cash per unit, basic	**$ 0.50**	$ 0.48	**$ 2.27**	$ 2.66
Standardized distributable cash per unit, diluted	**$ 0.50**	$ 0.47	**$ 2.25**	$ 2.62
Standardized distributable cash payout ratio (3)	**2.05**	2.14	**1.80**	1.52
Distributions declared per unit	**$ 1.02**	$ 1.02	**$ 4.08**	$ 4.05
Net income as a percentage of cash distributions declared	**51%**	51%	**18%**	82%
Cash flow from operating activities as a percentage of cash distributions declared	**126%**	108%	**127%**	136%

(1) Please refer to our discussion of productive capacity maintenance below.
(2) Consists of proceeds from the Distribution Reinvestment and Optional Purchase Plan, the Trust Unit Rights Incentive Plan and the Trust Unit Savings Plan.
(3) Represents cash distributions declared divided by standardized distributable cash.

We strive to fund both distributions and maintenance capital programs primarily from funds flow. We initially budget our capital programs at approximately 40-50 percent of annual funds flow. We believe that proceeds from the Distribution Reinvestment 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 funds flow, capital efficiency and debt levels.

Productive capacity maintenance is the amount of capital funds required in a period for an enterprise to maintain its future cash flow from operating activities at a constant level. As commodity prices can be volatile and short-term variations in production levels are often experienced in our industry, we define our productive capacity as production on a barrel of oil equivalent basis. A quantifiable measure for these short-term variations is not objectively determinable or verifiable due to various factors including the inability to distinguish natural production declines from the effect of production additions resulting 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 standardized distributable cash is our capital expenditures during the period excluding the cost of any asset acquisitions or proceeds of any asset dispositions. We believe that our current capital programs, based on 40-50 percent of forecast annual funds flow and our current view of our assets and opportunities, including particularly our oil sands project, and our proposed enhanced oil recovery projects, and our outlook for commodity prices and industry conditions, should be sufficient to maintain our productive capacity in the medium-term. We set our hurdle rates for evaluating potential development and optimization projects according to these parameters. Due to the risks inherent in the oil and natural gas industry, particularly our exploration and development activities and variations in commodity prices, there can be no assurance that capital programs, whether limited to the excess of funds flow over distributions or not, will be sufficient to maintain or increase our production levels or cash flow from operating activities. Penn West historically incurred a larger

proportion of its development expenditures in the first quarter of each calendar year to exploit winter-only access properties. As we strive to maintain sufficient credit facilities and appropriate levels of debt, this seasonality is not currently expected to influence our distribution policies.

Our calculation of standardized distributable cash 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 standardized distributable cash calculation, includes a deduction for abandonment expenditures incurred during each period. We believe that our current environmental programs will be sufficient to fund our asset retirement obligations over the life of our reserves. Distribution policies are set by our Board of Directors based on funds flow. Distributions in excess of net income may include an economic return of capital to unitholders.

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 ratios)	To December 31, 2007
Cumulative standardized distributable cash from operations (1)	$ 1,562.9
Issue of trust units	290.0
Bank borrowing and working capital change	258.3
Cumulative cash distributions declared (1)	$ 2,111.2
Standardized distributable cash payout ratio (2)	1.35

(1) Subsequent to the trust conversion on May 31, 2005.
(2) Represents cumulative cash distributions declared divided by cumulative standardized distributable cash.

Financial Instruments

During 2007, Penn West had $201.6 million of unrealized losses on risk management activities compared to a $48.6 million gain in 2006. The losses in 2007 were primarily due to record oil prices experienced in the latter part of the year.

As at December 31, 2007 we had WTI crude oil collars on approximately 30,000 barrels per day for 2008 with an average floor price of US$66.17 per barrel and an average ceiling price of US$81.75 per barrel. In addition, Penn West has AECO natural gas collars on approximately 67.5 mmcf per day for 2008 with an average floor price of $6.68 per mcf and an average ceiling price of $7.70 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 floating interest rate debt. Further to this, in the fourth quarter of 2007, we entered into additional interest swaps that fix the interest rate for three years at 4.26 percent on $100 million of floating interest rate debt.

In the third quarter of 2007, we entered into foreign exchange forward contracts to fix the principal repayment on debt amounts totalling US$250 million at an exchange rate of approximately par.

In January 2008, we entered into 10-year U.S. Treasury forward contracts on a notional principal amount of $250 million at an average fixed treasury rate of 3.6778 percent until June 30, 2008.

Other financial instruments outstanding at December 31, 2007 were Alberta electricity contracts, which fix 2008 electricity costs on 32 megawatts at $75.02 per megawatt-hour and in both 2009 and 2010 fix electricity costs on 30 megawatts at $76.23 per megawatt-hour.

Mark to market amounts on all financial instruments outstanding at December 31, 2007 are summarized in note 11 to the audited consolidated financial statements. Canetic and Vault had entered into a number of financial instruments that were assumed upon closing of these deals. Please refer to Penn West's website at www.pennwest.com for details of all financial instruments currently outstanding.

Outlook

This outlook section is included to provide unitholders with information as to management's expectations as at March 6, 2008 for production, revenues and net capital expenditures for 2008 and readers are cautioned that the information may not be appropriate for any other purpose. This information constitutes forward-looking information. Readers should note the assumptions, risks and disclaimers under "Forward-Looking Statements".

The outlook for oil prices remains strong, while the outlook for natural gas prices remains relatively weak and the Canadian dollar remains strong compared to the U.S. dollar. Including the Canetic and Vault acquisitions, Penn West forecasts 2008 production of between 195,000 boe per day and 205,000 boe per day. Based on a forecast WTI oil price of US$80.00 per barrel, a $6.75 per GJ natural gas price at AECO and a CAD/USD exchange rate of par for 2008, funds flow for 2008 is forecast to be between $2.0 billion and $2.1 billion. Based on this level of funds flow and other factors, we estimate 2008 net capital expenditures of approximately $960 million.

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on 2008 financial results, including the impact of the Canetic and Vault acquisitions, and before considering hedging impacts, are outlined in the table below.

Change of	Change	Impact on Funds Flow (1) $ millions	Impact on Funds Flow (1) $/unit	Impact on Net Income (1) $ millions	Impact on Net Income (1) $/unit
Price per barrel of liquids	$ 1.00	30.3	0.08	21.2	0.06
Liquids production	1,000 bbls/day	14.7	0.04	4.8	0.01
Price per mcf of natural gas	$ 0.10	17.2	0.05	12.0	0.03
Natural gas production	10 mmcf/day	14.2	0.04	0.8	—
Effective interest rate	1%	31.4	0.08	22.0	0.06
Exchange rate ($US per $CAD)	$ 0.01	23.9	0.06	16.8	0.04

(1) The impact on funds flow and net income is computed based on 2008 forecast commodity prices and production volumes. The impact on net income assumes that the distribution levels are not adjusted for changes in funds flow thus changing the incremental future income tax rate.

Contractual Obligations and Commitments

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

(millions)	2008	2009	2010	2011	2012	Thereafter
Long-term debt	$ —	$ —	$ 1,485.4	$ —	$ —	$ 457.8
Transportation	13.9	5.8	2.2	0.1	—	—
Transportation ($US)	2.3	2.3	2.3	2.3	2.3	6.4
Power infrastructure	6.2	4.2	4.2	4.2	4.2	7.6
Drilling rigs	7.7	2.4	1.2	—	—	—
Purchase obligations (1)	13.3	13.3	13.3	13.3	13.2	41.1
Office lease	$ 19.4	$ 19.6	$ 17.3	$ 16.5	$ 16.2	$ 104.3

(1) These amounts represent estimated commitments of $84.4 million for CO_2 purchases and $23.1 million for processing fees related to interests in the Weyburn Unit.

The $4.0 billion syndicated credit facility expires on January 11, 2011. If we were not successful in renewing or replacing the facility, we could be required to repay all amounts then outstanding on the facility or enter term bank loans. As we strive to maintain our leverage ratios at relatively modest levels, we believe we will be successful in renewing or replacing our credit facility on acceptable terms.

Equity Instruments

Trust units issued:	
As at December 31, 2007	242,663,164
Issued on exercise of trust unit rights	330,370
Issued to employee savings plan	217,988
Issued pursuant to distribution reinvestment plan	1,116,862
Issued on Canetic acquisition	124,348,739
Issued on Vault acquisition	5,550,923
As at March 6, 2008	374,228,046
Trust unit rights outstanding:	
As at December 31, 2007	14,486,084
Granted	11,296,752
Exercised	(330,370)
Forfeited	(162,244)
As at March 6, 2008	25,290,222

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Penn West maintains disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed by Penn West in its annual filings, interim filings (as these terms are defined in Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings) and other reports filed or submitted by it under provincial and territorial securities legislation is recorded, processed, summarized and reported within the required time periods. Our Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of our disclosure controls and procedures as of the end of the period covered by the annual filings, being December 31, 2007, have concluded that, as of such date, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by Penn West in reports that it files or submits is (i) recorded, processed, summarized and reported within the time periods as required, and (ii) accumulated and made known to management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and, as indicated in the preceding paragraph, the Chief Executive Officer and Chief Financial Officer believe that our disclosure controls and procedures are effective at that reasonable assurance level, although the Chief Executive Officer and Chief Financial Officer do not expect that the disclosure controls and procedures 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.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the design and effectiveness of our internal control over financial reporting as of the end of the fiscal year covered by this report based on the framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control — Integrated Framework. Based on this evaluation, management concluded that as of December 31, 2007, Penn West did maintain effective internal control over financial reporting. There have been no changes in Penn West's internal control over financial reporting during both 2007 and the most recent interim period that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2007 was audited by KPMG LLP, an independent registered public accounting firm, as stated in their report.

Accounting Changes and Pronouncements

Effective January 1, 2007, the Trust adopted new Canadian accounting standards issued by the CICA, these being "Comprehensive Income", "Financial Instruments – Disclosure and Presentation", "Hedges", "Financial Instruments – Recognition and Measurement", and "Equity". The adoption of these standards has had no material impact on the Trust's net income or funds flows.

Financial Instruments

Financial instruments are measured at fair value on the balance sheet upon initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified in one of the following categories: held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities as defined under CICA Handbook Section 3855.

Subsequent measurement and changes in fair value will depend on initial classification, as follows: held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net income; and available-for-sale financial instruments are measured at fair value with changes in fair value recorded in Other Comprehensive Income ("OCI") until the instrument or a portion thereof is derecognized or impaired, at which time the amounts would be recorded in net income.

As the Trust elected to discontinue hedge accounting in 2005, the adoption of these standards did not change the Trust's accounting for financial instruments. Cash and cash equivalents are designated as held-for-trading and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable and accrued revenues are designated as loans and receivables. Accounts payable and accrued liabilities and long-term debt are designated as other liabilities. Risk management assets and liabilities are derivative financial instruments classified as held-for-trading.

Embedded Derivatives

An embedded derivative is a component of a contract that affects the contract terms in relation to another factor, for example rent costs that fluctuate with oil prices. These "hybrid" contracts are considered to consist of a "host" contract plus an "embedded derivative". The embedded derivative is separated from the host contract and accounted for as a derivative if certain conditions are met. These include:

- The economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract;
- If the embedded derivative separated meets the definition of a derivative; and
- The hybrid contract is not measured at fair value or classified as held-for-trading.

The Trust currently has no material embedded derivatives.

Comprehensive Income

Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources. It consists of net income and OCI. OCI refers to items recognized in comprehensive income that are excluded from net income calculated in accordance with GAAP. The Trust currently has no items requiring separate disclosure as OCI on a Statement of Comprehensive Income.

Future Accounting Pronouncements

Three new Canadian accounting standards have been issued: "Financial Instruments – Disclosure", "Capital Disclosure" and "Goodwill and Intangible Assets". These will require additional disclosure in the Trust's financial statements commencing January 1, 2008 related to the Trust's financial instruments as well as the management of capital. The goodwill and intangible assets section is effective January 1, 2009.

Related-Party Transactions

During 2007, Penn West paid $1.3 million (2006 – $4.1 million) of legal fees to a law firm of which a partner is also a director of Penn West.

Off-Balance-Sheet Financing

We have off-balance-sheet financing arrangements consisting of operating leases. 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 2007 and 2006, 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, 2007.

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 6 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 funds 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, 2007.

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 impact on our business, distribution policies and unitholders of the SIFT tax and the different actions that we might take in response to the SIFT tax; the impact on our reserves and business of the new Alberta royalty framework drilling plans; sufficiency of insurance related to Wildboy costs and losses; tie-in of wells; environmental regulation compliance costs and strategy; production estimates; netback estimates; our business strategy, including our strategy in respect of our Peace River Oil Sands project, and our coal bed methane, shale gas and enhanced oil recovery projects; product balance; the sufficiency of our environmental program; funding sources for distributions, distribution levels and whether a special distribution will be made in 2007; the funding of our asset retirement obligations; our beliefs and outlook for the maintenance of productive capacity; our outlook for oil and natural gas prices; our forecast 2008 net capital expenditures and the allocation and funding thereof; the section on “Outlook” which sets forth management’s expectations as to production, revenues and net capital expenditures for 2008; the sensitivity of our assumptions regarding 2008 funds flow and net income to changes in certain operational and financial metrics; currency exchange rates; our forecast funds flow; the nature and effectiveness of our risk management strategies; our belief that we will be successful in renewing or replacing our credit facilities on acceptable terms when they expire; the quantity and recoverability of our oil and natural gas reserves and resources, including the quantity of discovered heavy oil resources in place at the Peace River Oil Sands Project; and the ability of Penn West to economically develop its contingent resources at its Peace River Oil Sands Project and convert these resources into reserves.

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 capital expenditure levels; 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; the ability of insurance to offset the financial impact of the fire-related outage at the Wildboy natural gas plant; 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; and our ability to add production and reserves through our development and exploitation activities. In addition, the “Outlook” section is based on specific assumptions as to commodity prices and exchange rates, planned capital expenditures and our success in maintaining production and adding new production through our 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 natural 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 acquisition of Petrofund Energy Trust, the acquisition of C1 Energy Ltd. and Vault Energy Trust and the acquisition of Canetic Resources Trust; changes in tax law; changes in the Alberta royalty framework; uncertainty of obtaining required approvals for acquisitions and mergers; 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 Penn West’s Annual Information Form is available on SEDAR at www.sedar.com.

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.

[signed] "William E. Andrew"	[signed] "Murray R. Nunns"	[signed] "Todd H. Takeyasu"
William E. Andrew Chief Executive Officer	**Murray R. Nunns** President and COO	**Todd H. Takeyasu** Executive Vice President and CFO

March 6, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Penn West Petroleum Ltd., the administrator of Penn West Energy Trust and the Unitholders of Penn West Energy Trust

We have audited Penn West Energy Trust's ("the Trust")'s internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the year ended December 31, 2007, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 6, 2008 expressed an unqualified opinion on those consolidated financial statements.

[signed] "KPMG LLP"

Chartered Accountants

Calgary, Canada

March 6, 2008

AUDITORS' REPORT TO THE UNITHOLDERS

To the Unitholders of Penn West Energy Trust

We have audited the consolidated balance sheets of Penn West Energy Trust ("the Trust") as at December 31, 2007 and 2006 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the year ended December 31, 2007, we also conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 6, 2008 expressed an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

[signed] "KPMG LLP"

Chartered Accountants
Calgary, Canada

March 6, 2008

CONSOLIDATED BALANCE SHEETS

(CAD millions)	As at December 31 2007	2006
ASSETS		
Current		
Accounts receivable	**$ 277.5**	$ 268.7
Risk management (note 11)	**—**	54.0
Future income taxes (note 7)	**44.3**	—
Other	**45.7**	56.0
	367.5	378.7
Property, plant and equipment (note 3)	**7,413.5**	7,039.0
Goodwill (note 4)	**652.0**	652.0
	8,065.5	7,691.0
	$ 8,433.0	$ 8,069.7
LIABILITIES AND UNITHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	**$ 359.3**	$ 384.1
Distributions payable	**82.5**	80.6
Risk management (note 11)	**147.6**	—
	589.4	464.7
Long-term debt (note 5)	**1,943.2**	1,285.0
Asset retirement obligations (note 6)	**413.5**	339.1
Future income taxes (note 7)	**917.4**	792.6
	3,863.5	2,881.4
Unitholders' equity		
Unitholders' capital (note 8)		
(Units outstanding 2007 –242,663,164; 2006 – 237,126,219)	**3,877.1**	3,712.4
Contributed surplus (note 8)	**35.3**	16.4

Retained earnings	**657.1**	1,459.5
	4,569.5	5,188.3
	$ 8,433.0	$ 8,069.7

Subsequent events (notes 5 and 18)
Contractual obligations and commitments (note 13)

See accompanying notes to the audited consolidated financial statements.

Approved on behalf of Penn West Energy Trust, by Penn West Petroleum Ltd. as Administrator:

[signed] "John A. Brussa"	[signed] "James C. Smith"
John A. Brussa Chairman	**James C. Smith** Director

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS

(CAD millions, except per unit amounts)	Years ended December 31 2007	2006
Revenues		
Oil and natural gas	**$ 2,458.8**	$ 2,033.7
Royalties	**(450.8)**	(388.0)
	2,008.0	1,645.7
Risk management gain (loss) (note 11)		
Realized	**3.0**	67.2
Unrealized	**(182.0)**	42.8
	1,829.0	1,755.7
Expenses		
Operating (note 9)	**517.7**	429.1
Transportation	**24.1**	24.5
General and administrative (note 9)	**65.8**	44.5
Financing (note 5)	**92.4**	49.3
Depletion, depreciation and accretion	**896.7**	654.7
Risk management (gain) loss (note 11)	**19.6**	(5.8)
Unrealized foreign exchange gain	**(38.2)**	—
	1,578.1	1,196.3
Income before taxes	**250.9**	559.4
Taxes		
Future income tax expense (reduction) (note 7)	**75.4**	(106.2)
Net income	**175.5**	665.6
Retained earnings, beginning of year	**1,459.5**	1,605.7
Distributions declared	**(977.9)**	(811.8)
Retained earnings, end of year	**$ 657.1**	$ 1,459.5
Net income per unit		
Basic	**$ 0.73**	$ 3.32
Diluted	**$ 0.73**	$ 3.27
Weighted average units outstanding (millions)		
Basic	**239.4**	200.8
Diluted	**241.5**	203.5

See accompanying notes to the audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(CAD millions)	Years ended December 31 2007	2006
Operating activities		
Net income	**$ 175.5**	$ 665.6
Depletion, depreciation and accretion	**896.7**	654.7
Future income tax expense (reduction) (note 7)	**75.4**	(106.2)
Unit-based compensation (note 9)	**20.5**	11.3

Risk management (gain) loss (note 11)	**201.6**	(48.6)
Unrealized foreign exchange gain	**(38.2)**	—
Asset retirement expenditures	**(51.5)**	(26.9)
Change in non-cash working capital (note 14)	**(38.2)**	(43.6)
	1,241.8	1,106.3
Investing activities		
Acquisition of property, plant and equipment	**(576.1)**	(18.2)
Disposition of property, plant and equipment	**133.2**	12.6
Additions to property, plant and equipment	**(697.3)**	(572.3)
Petrofund acquisition costs (note 17)	**—**	(25.0)
Change in non-cash working capital (note 14)	**14.9**	11.7
	(1,125.3)	(591.2)
Financing activities		
Proceeds from issuance of notes (note 5)	**509.1**	—
Increase in bank loan	**187.3**	132.6
Issue of equity	**32.0**	22.5
Distributions paid	**(844.9)**	(685.7)
Settlement of future income tax liabilities on trust conversion	**—**	15.5
	(116.5)	(515.1)
Change in cash	**—**	—
Cash, beginning of year	**—**	—
Cash, end of year	**$ —**	$ —
Interest paid	**$ 94.5**	$ 44.4
Income taxes paid (recovered)	**$ (2.4)**	$ 8.6

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 11)

1. Structure of Penn West

Penn West Energy Trust ("Penn West" or the "Trust") 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 or partnership interests, 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 the notes 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 and deductions.

On June 2, 2005, the trust units commenced trading on the TSX under the symbol "PWT.UN". On June 22, 2006, the trust units commenced trading on the NYSE under the symbol "PWE".

2. Significant accounting policies

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

a) Principles of consolidation

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 for 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 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 cost 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.

Financial instruments are measured at fair value on the balance sheet upon initial recognition of the instrument. Measurement in subsequent years depends on whether the financial instrument has been classified in one of the following categories: held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities.

Subsequent measurement and changes in fair value will depend on initial classification, as follows: held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net income; available-for-sale financial instruments are measured at fair value with changes in fair value recorded in Other Comprehensive Income ("OCI") until the instrument or a portion thereof is derecognized or impaired at which time the amounts would be recorded in net income.

As the Trust elected to discontinue hedge accounting in 2005, the adoption of these standards did not change the Trust's accounting for financial instruments. Cash and cash equivalents are designated as held-for-trading and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable and accrued revenues are designated as loans and receivables. Accounts payable and accrued liabilities and long-term debt are designated as other financial liabilities. All risk management assets and liabilities are derivative financial instruments classified as held-for-trading.

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 long-term debt, 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) Unit-based compensation

The Trust has a trust unit rights incentive plan, as outlined in note 9. 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.

i) Revenue recognition

Revenues from the sale of crude oil, natural gas liquids and natural gas are recognized when title passes from Penn West Petroleum Ltd. ("the Company") to the purchaser.

j) Income taxes

Penn West uses 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 enacted or substantively enacted 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.

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, at December 31, or more frequently if circumstances arise that indicates impairment may have occurred. If impairment exists, the impairment amount is charged to earnings and is considered to be non-deductible for tax purposes.

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 are 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.

m) Transportation expense

Transportation relates to costs paid by the Trust for the shipping of natural gas, crude oil and NGL from the wellhead to the point of title transfer. These costs are recognized when the transportation is provided.

n) Per unit calculations

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.

o) Embedded derivatives

An embedded derivative is a component of a contract that affects the terms in relation to another factor, for example rent costs that fluctuate with oil prices. These "hybrid" contracts are considered to consist of a "host" contract plus an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative only if certain conditions are met. These include:

- the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract;
- if the embedded derivative separated meets the definition of a derivative; and
- the hybrid contract is not measured at fair value or classified as held for trading.

The Trust currently has no material embedded derivatives.

p) Comprehensive income

Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources. It consists of net income and OCI. OCI refers to items recognized in comprehensive income that are excluded from net income calculated in accordance with generally accepted accounting principles. The Trust currently has no items requiring separate disclosure as OCI on a statement of Comprehensive Income.

q) Transaction costs

Transaction costs are capitalized when related to acquisitions and divestiture activities and expensed into net income as incurred during financing transactions.

Future accounting changes

Three new Canadian accounting standards have been recently issued: “Financial Instruments – Disclosure”, “Capital Disclosures” and “Goodwill and Intangible Assets”.

The Financial Instruments – Disclosure section outlines standards of disclosures and presentation for financial instruments, effective January 1, 2008. This requires additional disclosure by the Trust and will be implemented in the first quarter of 2008.

The Capital Disclosure section becomes effective on January 1, 2008 and specifies disclosures relating to capital, including a qualitative discussion on an entity’s objectives, polices and processes for managing capital and summary quantitative data regarding what is managed as capital. This section requires additional disclosure by the Trust and will be implemented in the first quarter of 2008.

The Goodwill and Intangible Assets section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. The new section becomes effective on January 1, 2009. The Trust is currently assessing the impact of this new section.

3. Property, plant and equipment

	December 31	
	2007	**2006**
Oil and natural gas properties, including production and processing equipment	**$ 10,925.1**	$ 9,683.2
Accumulated depletion and depreciation	**(3,511.6)**	(2,644.2)
Net book value	**$ 7,413.5**	$ 7,039.0

Other than Penn West’s net share of capital overhead recoveries, no general and administrative expenses are capitalized. In 2007, additions to property, plant and equipment included a $96.6 million (2006 – $55.9 million) increase related to additions to asset retirement obligations; and a $5.1 million (2006 – $1.7 million) addition for future income taxes recorded on property acquisitions. The lower of cost and market of unevaluated property excluded from the depletion base as at December 31, 2007 was $303 million (December 31, 2006 – $303 million). The depletion and depreciation calculation includes future capital costs to develop proved reserves of $729 million (2006 – $718 million).

An impairment test was performed on the costs capitalized to oil and natural gas properties at December 31, 2007 and 2006. The estimated undiscounted future net cash flows from proved reserves, using forecast prices, exceeded the carrying amount of the oil and natural gas property interests less the cost of unproved properties.

The following table outlines benchmark prices used in the impairment test:

	WTI ($US/ bbl)	AECO ($CAD/mcf)	Exchange rate ($US equals $1 CAD)
2008	$ 90.81	$ 6.63	1.00
2009	87.00	7.38	1.00
2010	84.33	7.65	1.00
2011	82.39	7.65	1.00
2012 – 2018	$ 84.54	$ 8.06	1.00
Thereafter (inflation percentage)	2.0	2.0	—

4. Goodwill

In 2006, Penn West recorded $652 million in goodwill in conjunction with the Petrofund Energy Trust (“Petrofund”) acquisition. The goodwill impairment test is completed annually on December 31 or more frequently if circumstances arise that indicate an impairment may have occurred. At December 31, 2007 and 2006 an impairment test was performed and it was determined that there was no impairment to the goodwill balance.

5. Long-term debt

	December 31	
	2007	2006
Bankers' acceptances and prime rate loans	**$ 1,472.3**	$ 1,285.0
U.S. Senior unsecured notes		
5.68%, US$160 million, maturing May 31, 2015	**158.6**	—
5.80%, US$155 million, maturing May 31, 2017	**153.7**	—
5.90%, US$140 million, maturing May 31, 2019	**138.8**	—
6.05%, US$20 million, maturing May 31, 2022	**19.8**	—
Total long-term debt	**$ 1,943.2**	$ 1,285.0

As at December 31, 2007, the Company had an unsecured, extendible, three-year revolving syndicated credit facility with an aggregate borrowing limit of $2.1 billion, with an expiry date of August 25, 2010. In January 2008, the Company amended its unsecured, revolving syndicated credit facility to an aggregate borrowing limit of $4.0 billion expiring on January 11, 2011, to enable the cancellation of the credit facilities of Canetic Resources Trust ("Canetic") and Vault Energy Trust ("Vault"). The facility is made up of two revolving tranches; tranche one of the facility is $3.25 billion and extendible and tranche two is $750 million and non-extendible. The credit facility contains financial covenants consisting of debt to earnings before interest, taxes and depletion, depreciation and amortization ("EBITDA") and debt to capitalization ratios. During 2007, the weighted average effective interest rate under the credit facility was five percent.

Financing costs include interest expense on long-term debt of $90.1 million for the year ended December 31, 2007 (2006 – $47.7 million).

Letters of credit totalling $0.3 million were outstanding on December 31, 2007 (December 31, 2006 – $0.4 million) that reduced the amount otherwise available to be drawn on the syndicated facility.

The US$475 million of senior unsecured notes are subject to the financial covenant that consolidated debt to consolidated capitalization shall not exceed 55 percent except in the event of a material acquisition where it is not to exceed 60 percent. The estimated fair value of the principal and interest obligations under the notes, calculated using estimated market rates on December 31, 2007 was $457.8 million.

In January 2008, we entered into 10-year U.S. Treasury forward contracts on a notional principal amount of $250 million at an average fixed treasury rate of 3.6778 percent until June 30, 2008.

6. 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 using external consultants assuming current technology and enacted legislation.

The total inflated and undiscounted amount to settle Penn West's asset retirement obligations at December 31, 2007 was $2.6 billion (December 31, 2006 – $2.2 billion). The asset retirement obligation was determined by applying an inflation factor of 2.0 percent (2006 – 2.0 percent) and the inflated amount was discounted using a credit-adjusted rate of 7.0 percent (2006 – 7.0 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. The well reclamation cost assumptions were revised upwards in 2007 to reflect the overall increases in costs experienced. Future cash flows from operating activities are expected to fund the obligations.

Changes to asset retirement obligations were as follows:

	2007	2006
Balance, beginning of year	**$ 339.1**	$ 192.4
Liabilities incurred during the year	**35.7**	30.2
Petrofund liabilities assumed on acquisition	**—**	98.0
Increase in liability due to change in estimate	**60.9**	25.7
Liabilities settled during the year	**(51.5)**	(26.9)
Accretion charges	**29.3**	19.7
Balance, end of year	**$ 413.5**	$ 339.1

7. Income taxes

In 2007, the Government of Canada enacted new tax legislation on publicly traded income trusts. Under the new rules, effective for the 2011 tax year, distributions of certain types of income will no longer be deductible for income tax purposes by certain specified investment flow-through ("SIFT") entities, including Penn West, and any resultant taxable income at the trust level will be taxed at an approximation of the corporate tax rate. At the time of the enacted legislation, the SIFT tax rate was 31.5 percent, which led to an additional $325.5 million future income tax liability and future income tax expense recorded in the second quarter of 2007. In accordance with GAAP, prior to the enactment, the temporary differences in the Trust were not reflected in future income taxes. In the fourth quarter of 2007 the Government of Canada enacted tax rate reductions which included a lower SIFT tax rate of 29.5 percent in 2011 and 28.0 percent in 2012 and subsequent years and a total reduction to future corporate income tax rates of 3.5 percent. As a result of the above legislation, a $106.4 million future income tax reduction was recorded during the fourth quarter of 2007. The Trust's temporary differences relate primarily to the net book value of oil and natural gas properties in excess of tax pools assumed on the Petrofund acquisition closing June 30, 2006.

On February 26, 2008, the Government of Canada, in its Federal Budget, announced changes to the SIFT tax rules. The provincial component of the SIFT tax will be based on the provincial rates where the SIFT has a permanent establishment rather than using a 13 percent flat rate. For Penn West, the SIFT tax rate applicable in 2012 is expected to fall from 28 percent to 25 percent. As the tax rate change has not been substantively enacted, no future income tax rate benefit has been recorded in the financial statements.

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

	2007	2006
Property, plant and equipment	**$ (1,027.1)**	$ (876.4)
Risk management	**44.3**	(17.6)
Asset retirement obligations	**109.7**	101.4
Net future income tax liability	**$ (873.1)**	$ (792.6)
Future income tax asset	**44.3**	—
Future income tax liability	**$ (917.4)**	$ (792.6)

The Trust currently maintains an income tax status that permits it to deduct distributions to unitholders in addition to other items.

The provision for (reduction 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	
	2007	2006
Income before taxes	**$ 250.9**	$ 559.4
Combined statutory tax rate	**32.8%**	35.2%
Computed income tax provision	**$ 82.2**	$ 197.0
Increase (decrease) resulting from:		
Net Income attributable to the trust	**(203.9)**	(197.4)
Tax rate reductions	**(128.8)**	(108.1)
Effect of SIFT tax	**325.5**	**—**
Unit-based compensation	**5.5**	3.4
Unrealized foreign exchange	**(5.1)**	**—**
Non-deductible Crown payments, net	**—**	36.1
Resource allowance	**—**	(38.4)
Other	**—**	1.2
Future income tax expense (reduction)	**$ 75.4**	$ (106.2)

8. 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

Voting Trust Units	Units	Amount
Balance, December 31, 2005	163,290,013	$ 561.0
Issued on exercise of trust unit rights (1)	407,750	10.6

Issued to employee trust unit savings plan	295,449	12.3
Issued to distribution reinvestment plan	2,459,870	96.1
Issued on Petrofund acquisition	70,673,137	3,032.4
Balance, December 31, 2006	237,126,219	3,712.4
Issued on exercise of trust unit rights (1)	665,155	16.1
Issued to employee trust unit savings plan	532,840	17.5
Issued to distribution reinvestment plan	4,338,950	131.1
Balance, December 31, 2007	242,663,164	$ 3,877.1

(1) The exercise of trust unit rights is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

Special voting units

No Special Voting Units were issued.

c) Contributed surplus

	2007	2006
Balance, beginning of year	**$ 16.4**	$ 5.5
Unit-based compensation expense	**20.5**	11.3
Benefit on rights exercised (1)	**(1.6)**	(0.4)
Balance, end of year	**$ 35.3**	$ 16.4

(1) The exercise of trust unit rights is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

9. Unit-based compensation

Trust unit rights incentive plan

Penn West has 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 rights are granted at prices administered 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 of grant. If certain conditions are met, the exercise price per unit may be reduced by deducting from the grant price the aggregate of all distributions, on a per unit basis, paid by Penn West after the grant date. 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 generally vest over a three-year period and expire four years after the date of the grant.

Trust Unit Rights	Number Outstanding	Weighted Average Exercise Price	Weighted Average Grant Date Fair Value
Outstanding, December 31, 2005	9,447,625	$ 28.45	$ 2.92
Granted	3,257,622	39.77	8.10
Exercised	(407,750)	24.65	2.15
Forfeited	(1,012,625)	33.38	5.58
Balance before reduction of exercise price	11,284,872	30.89	4.21
Reduction of exercise price for distributions paid	—	(3.13)	—
Outstanding, December 31, 2006	**11,284,872**	**$ 27.76**	**$ 4.21**
Granted	**5,189,346**	**33.24**	**6.38**
Exercised	**(665,155)**	**21.91**	**2.69**
Forfeited	**(1,322,979)**	**29.88**	**5.73**
Balance before reduction of exercise price	**14,486,084**	**29.80**	**4.91**
Reduction of exercise price for distributions paid	**—**	**(4.11)**	**—**
Outstanding, December 31, 2007	**14,486,084**	**$ 25.69**	**$ 4.91**

At December 31, 2007, exercisable trust units totaled 2,742,359 (2006 – 1,125,300) for a weighted average exercise price of $22.53 (2006 – $23.16) and a weighted average grant date fair value of $3.75 (2006 – $2.37).

	Unit Rights Outstanding			Unit Rights Exercisable	
Range of Grant Prices	Number Outstanding	Weighted Average Exercise Price (1)	Weighted Remaining Contractual Life (years) (2)	Number Exercisable	Weighted Average Exercise Price (1)
$ 26.00 – $30.99	6,061,745	$ 19.65	3.6	1,765,576	$ 18.59
$ 31.00 – $35.99	6,401,700	28.55	3.6	565,633	26.04
$ 36.00 – $40.99	1,461,989	33.80	3.8	292,300	33.60
$ 41.00 – $45.99	560,650	37.13	4.7	118,850	37.16
	14,486,084	**$ 25.69**	**3.7**	**2,742,359**	**$ 22.53**

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

(2) Rights granted under the plan prior to November 13, 2006 expire after 6 years, rights granted after this date expire after 4 years.

Penn West recorded unit-based compensation expense of $20.5 million for the year ended December 31, 2007, of which $5.5 million was charged to operating expense and $15.0 million was charged to general and administrative expense (2006 – $11.3 million, $2.8 million and $8.5 million respectively). Unit-based compensation expense is based on the fair value of rights issued and is amortized over the remaining vesting periods on a straight-line basis.

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	
	2007	**2006 (2)**
Average fair value of trust unit rights granted (per unit)	**$ 6.38**	$ 8.10
Expected life of trust unit rights (years)	**3.0**	4.5
Expected volatility (average)	**24.9%**	23.8%
Risk-free rate of return (average)	**4.2%**	4.1%
Distribution yield (1)	**13.1%**	9.9%

(1) Represents distributions declared as a percentage of the market price of trust units and does not account for any portion of distributions that represent a return of capital.

(2) 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.

The expected volatility of the trust unit rights was based on the historical unit price volatility of the Trust and the volatility of certain competitors. The expected life of the trust unit rights was based on expected exercise patterns and the forfeiture rate was based on historical employee forfeiture patterns.

Trust unit savings plan

Penn West has an employee trust unit savings plan for the benefit of all employees. Under the savings plan, employees may elect to contribute up to 10 percent of their salary and Penn West matches these 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 at prevailing market prices. During 2007, 532,840 treasury units (2006 – 295,449) were contributed to the plan at an average of $32.86 per unit (2006 – $41.71) and a total cost of $17.5 million (2006 – $12.3 million). No trust units have been purchased in the open market since the trust conversion.

10. 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	**2007**	**2006**
Balance, beginning of year	**$ 1,133.3**	$ 321.5
Distributions declared	**977.9**	811.8
Balance, end of year	**$ 2,111.2**	$ 1,133.3
Distributions per unit (1)	**$ 4.08**	$ 4.05
Accumulated cash distributions per unit, beginning of year	**6.02**	1.97
Accumulated cash distributions per unit, end of year	**$ 10.10**	$ 6.02

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

11. Risk management

Financial instruments included in the balance sheets consist of accounts receivable, fair values of derivative financial instruments, current liabilities and long-term debt. The fair values of these financial instruments approximate their carrying amounts, except for the U.S. Senior notes described in Note 5, 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 long-term debt.

Nearly 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 funds flows are sufficient to fund planned capital programs and distributions, 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 or by transactions in fixed rate instruments.

Crude oil sales are referenced to or denominated in U.S. dollars. Crude oil prices realized in Canadian dollars are accordingly impacted directly by Canadian to U.S. exchange rates. Penn West currently has a portion of long-term debt held in U.S. dollars which is also affected by foreign exchange fluctuations. From time to time, Penn West may use financial instruments to fix future exchange rates.

Changes in the fair value of all outstanding financial commodity, power, interest rate and foreign exchange 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 outstanding on December 31, 2007:

Risk Management	**2007**	2006
Balance, beginning of year	**$ 54.0**	$ 8.5
Unrealized gain (loss) on financial instruments:		
Commodity collars	**(182.0)**	51.3
Electricity swaps	**(18.3)**	(5.6)
Interest rate swaps	**0.5**	(0.2)
Foreign exchange forwards	**(1.8)**	—
Fair value, end of year	**$ (147.6)**	$ 54.0

Penn West had the following financial instruments outstanding as at December 31, 2007:

	Notional Volume	**Remaining Term**	**Pricing**	**Market Value**
Crude oil collars				
WTI Collars	10,000 bbls/d	Jan/08 – Jun/08	US$ 60.00 to 94.55/bbl	$ (9.2)
WTI Collars	20,000 bbls/d	Jan/08 – Dec/08	US$ 67.50 to 79.18/bbl	(109.8)
WTI Collars	10,000 bbls/d	Jul/08 – Dec/08	US$ 67.00 to 79.23/bbl	(24.9)
Natural gas collars				
AECO Collars	9,200 mcf/d	Jan/08 – Mar/08	$8.18 to $12.15/mcf	1.1
AECO Collars	46,000 mcf/d	Jan/08 – Oct/08	$6.64 to $7.79/mcf	(0.7)
AECO Collars	46,000 mcf/d	Apr/08 – Oct/08	$6.60 to $7.19/mcf	(2.0)
Electricity swaps				
Alberta Power Pool Swaps	32 MW	2008	$75.02/MWh	—
Alberta Power Pool Swaps	30 MW	2009	$76.23/MWh	0.1
Alberta Power Pool Swaps	30 MW	2010	$76.23/MWh	(0.7)
Interest rate swaps				
	$100.0	Jan/08 – Mar/08	4.356%	0.3
	$100.0	Jan/08 – Nov/10	4.264%	—
Foreign exchange forwards				
8-year term	US$80.0	2015	1.00934 CAD/USD	(0.6)
10-year term	US$80.0	2017	1.00165 CAD/USD	(0.6)
12-year term	US$70.0	2019	0.99125 CAD/USD	(0.2)
15-year term	US$20.0	2022	0.98740 CAD/USD	(0.4)
Total				$ (147.6)

A realized gain of $11.0 million (2006 – $17.3 million) on the electricity contracts has been included in operating costs.

Realized gains and losses on the interest rate swaps are charged to interest expense. During the year, the fixed rate and the floating rate were approximately equal, resulting in no reportable gain or loss being charged to interest rate expense in relation to the interest rate swaps.

12. Per unit amounts

The number of incremental units included in diluted earnings per unit is computed using the average volume-weighted market price of trust units for each interim period. In addition, contracts that could be settled in cash or trust units are assumed settled in trust units if unit settlement is more dilutive.

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

	Year ended December 31

	2007	2006
Basic	**239,374,970**	200,758,870
Diluted impact	**2,134,221**	2,750,624
Diluted	**241,509,191**	203,509,494

For the year ended December 31, 2007, 7.0 million trust unit rights (2006 – 1.7 million) were excluded in calculating the weighted average number of diluted trust units outstanding, as they were considered anti-dilutive.

13. Contractual obligations and commitments

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

	2008	2009	2010	2011	2012	Thereafter
Long-term debt	$ —	$ —	$ 1,485.4	$ —	$ —	$ 457.8
Transportation	13.9	5.8	2.2	0.1	—	—
Transportation ($US)	2.3	2.3	2.3	2.3	2.3	6.4
Power infrastructure	6.2	4.2	4.2	4.2	4.2	7.6
Drilling rigs	7.7	2.4	1.2	—	—	—
Purchase obligations (1)	13.3	13.3	13.3	13.3	13.2	41.1
Office lease	$ 19.4	$ 19.6	$ 17.3	$ 16.5	$ 16.2	$ 104.3

(1) These amounts represent estimated commitments of $84.4 million for CO_2 purchases and $23.1 million for processing fees related to interests in the Weyburn Unit.

The $4.0 billion syndicated credit facility expires on January 11, 2011. If we were not successful in renewing or replacing the facility, we could be required to repay all amounts then outstanding on the facility or enter term bank loans. We believe the facility will be renewed prior to that time.

14. Changes in non-cash working capital

	Year ended December 31	
	2007	2006
Accounts receivable	**$ (8.8)**	$ (54.3)
Other current assets	**10.3**	(27.0)
Accounts payable and accrued liabilities	**(24.8)**	68.2
Petrofund acquisition	**—**	(18.8)
	(23.3)	(31.9)
Operating activities	**(38.2)**	(43.6)
Investing activities	**14.9**	11.7
Financing activities	**—**	—
	$ (23.3)	$ (31.9)

15. Working capital components

	2007	2006
Components of accounts receivable		
Trade	**$ 54.2**	$ 31.0
Accruals	**221.6**	234.9
Other	**1.7**	2.8
	$ 277.5	$ 268.7
Components of other assets		
Prepaid expenses	**$ 23.4**	$ 23.4
Inventory	**22.3**	32.6
	$ 45.7	$ 56.0
Components of accounts payable and accrued liabilities		
Accounts payable	**$ 98.7**	$ 89.4
Royalty payable	**68.1**	71.4
Capital accrual	**113.4**	115.0
Operating accrual	**52.8**	92.0
Other	**26.3**	16.3
	$ 359.3	$ 384.1

16. Related-party transactions

During 2007, Penn West paid $1.3 million (2006 – $4.1 million) of legal fees in the normal course of business to a law firm of which a partner is also a director of Penn West.

17. Petrofund acquisition

Penn West purchased Petrofund effective June 30, 2006. Penn West accounted for the acquisition of Petrofund 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 was as follows:

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

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

(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.

18. Subsequent events

Canetic acquisition

On January 11, 2008, Penn West closed its acquisition of Canetic for a total acquisition cost of approximately $3.6 billion, funded through the issuance of 124.3 million trust units, calculated based on the volume weighted average trading price of the units around the date of the announcement, discounted by five percent. Bank debt and estimated working capital deficiency of $1.6 billion, including transaction costs, and convertible debentures with a fair value of $260.0 million was also assumed.

Vault acquisition

On January 10, 2008, Penn West closed its acquisition of Vault for a total acquisition cost of approximately $158.7 million funded through the issuance of 5.6 million trust units and cash paid for the warrants. The trust unit value was calculated based on the volume weighted average trading price of the units around the date of the announcement, discounted by five percent. Also assumed was bank debt plus estimated working capital deficiency of $126.4 million, including transaction costs, and convertible debentures with a fair value of $100.9 million. Subsequent to the close of the Vault acquisition, Penn West made its compulsory offer to redeem the Vault convertible debentures for cash at 101 percent of the principle amounts. On March 5, 2008, Penn West retired $23.8 million of the principle amount of the debentures for $24.5 million including the premium and accrued interest.

Exhibit 99.4

AUDITORS' REPORT ON RECONCILIATION TO UNITED STATES GAAP

To the Board of Directors of Penn West Petroleum Ltd., the administrator of Penn West Energy Trust

On March 6, 2008, we reported on the consolidated balance sheets of Penn West Energy Trust as at December 31, 2007 and 2006 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 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.

/s/ KPMG LLP

Chartered Accountants

Calgary, Canada

March 6, 2008

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:

(CAD millions, except per unit amounts)	Years ended December 31 2007	2006
Net income as reported in the Consolidated Statements of Income - Canadian GAAP	$ 175.5	$ 665.6
Adjustments		
Unit-based compensation (note (d))	28.7	(9.6)
Risk management activities (note (b))	—	(11.9)
Income tax effect of the above adjustments	—	3.6
Net and Other Comprehensive Income, as adjusted before cumulative effect of change in accounting policy	204.2	647.7
Cumulative effect of change in accounting policy, net of income taxes (note (d))	—	(9.2)
Net and Other Comprehensive Income - U.S. GAAP, as adjusted	$ 204.2	$ 638.5
Net income per trust unit before cumulative effect of change in accounting policy		
Basic	$ 0.85	$ 3.23
Diluted	0.85	3.20
Cumulative effect of change in accounting policy		
Basic	—	(0.05)
Diluted	—	(0.05)
Net income per trust unit		
Basic	0.85	3.18
Diluted	$ 0.85	$ 3.15
Weighted average number of trust units outstanding (millions)		
Basic	239.4	200.8
Diluted	240.7	202.6
Retained earnings (deficit) - U.S. GAAP		
Balance, beginning of period - U.S. GAAP	$ (2,395.8)	$ (3,723.8)
Net income - U.S. GAAP	204.2	638.5
Change in redemption value of trust units (note (c))	1,756.2	1,501.3
Distributions declared	(977.9)	(811.8)
Balance, end of period - U.S. GAAP	$ (1,413.3)	(2,395.8)

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

December 31, 2007 (CAD millions)	Canadian GAAP	U.S. GAAP
ASSETS		
Current		
Accounts receivable	$ 277.5	$ 277.5
Future income tax	44.3	44.3
Other	45.7	45.7
	367.5	367.5
Property, plant and equipment (note (a))	7,413.5	7,413.5
Goodwill	652.0	652.0
	8,065.5	8,065.5
	$ 8,433.0	**$ 8,433.0**
LIABILITIES AND UNITHOLDERS' EQUITY (DEFICIENCY)		
Current		
Accounts payable	$ 359.3	$ 359.3
Distributions payable	82.5	82.5
Risk management (note (b))	147.6	147.6
	589.4	589.4
Long-term debt	1,943.2	1,943.2
Asset retirement obligations	413.5	413.5
Unit rights liability (note (d))	—	24.8
Future income taxes	917.4	918.5
Total liabilities	3,863.5	3,889.4
Unitholders' mezzanine equity (note (c))	—	5,956.9
Unitholders' Equity (Deficiency)		
Unitholders' capital (note (c))	3,877.1	—
Contributed surplus (note (d))	35.3	—
Retained earnings (deficit) (note (c))	657.1	(1,413.3)
	4,569.5	(1,413.3)
	$ 8,433.0	**$ 8,433.0**

December 31, 2006 (CAD millions)	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
	7,691.0	7,691.0
	$ 8,069.7	**$ 8,069.7**
LIABILITIES AND UNITHOLDERS' EQUITY (DEFICIENCY)		
Current		
Accounts payable	$ 384.1	$ 384.1
Distributions payable	80.6	80.6
	464.7	464.7
Long-term debt	1,285.0	1,285.0
Asset retirement obligations	339.1	339.1
Unit rights liability (note (d))	—	34.1
Future income taxes	792.6	793.7
Total liabilities	2,881.4	2,916.6
Unitholders' mezzanine equity (note (c))	—	7,548.9
Unitholders' Equity (Deficiency)		
Unitholders' capital (note (c))	3,712.4	—
Contributed surplus (note (d))	16.4	—
Retained earnings (deficit) (note (c))	1,459.5	(2,395.8)
	5,188.3	(2,395.8)
	$ 8,069.7	**$ 8,069.7**

The application of U.S. GAAP would have no effects on reported cash flows.

(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 unproved 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 quarterly and, as elected by the Trust, recalculated seven business days prior to the filing date of the Trust's consolidated financial statements if an impairment was indicated on the balance

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sheet date. If there is an impairment indicated at the balance sheet date, which no longer exists at the time of the second test, no write down is required. At December 31, 2007, no impairment was indicated. As 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 2007 or 2006. Prices of $6.43 per mcf (2006 - - $7.27) for natural gas and $77.91 per barrel (2006 - $60.25) for liquids were used to calculate the future net revenues.

Depletion and depreciation of resource properties is calculated using the unit-of-production method based on production volumes before royalties in relation to proved reserves as estimated by independent petroleum engineers. In determining the depletable base, the estimated future costs to be incurred in developing proved reserves is included and the estimated equipment salvage values and the lower of cost and market of unevaluated properties is excluded. 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. Depletion and depreciation per gross equivalent barrel is calculated by converting natural gas volumes to barrels of oil equivalent ("BOE") using a ratio of 6 mcf of natural gas to one barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion and depreciation per BOE as calculated under U.S. GAAP for the year ended December 31, 2007 was $18.70 (2006 - $15.48).

(b) Derivative financial instruments

Effective January 1, 2007, the Trust adopted the new Canadian standards relating to financial instruments. The new guidance substantially harmonizes Canadian GAAP and 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. For the year ended December 31, 2007, no adjustment (2006 - $11.9 million, $8.3 million net of tax) to income was recorded for U.S. GAAP purposes for the amortization of the deferred gain on financial instruments previously recorded under Canadian GAAP as the balance had been fully amortized by the end of 2006 for Canadian GAAP purposes.

(c) 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, 2007, the Trust reclassified $5,956.9 million (December 31, 2006 - $7,548.9 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 $1,756.2 million to deficit for the year ended December 31, 2007 compared to a reduction of $1,501.3 million for 2006.

(d) 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

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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.

Under U.S. GAAP, 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. The Trust issues units from treasury to settle unit rights exercises. Contributed surplus amounts are eliminated under U.S. GAAP.

Rights granted under the rights plan are considered equity awards for Canadian GAAP purposes, a difference from U.S. GAAP. 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. Under U.S. GAAP, for the year ended December 31, 2007, compensation cost calculated was $28.7 million lower (2006 - $9.6 million higher) than compensation cost calculated under Canadian GAAP. The compensation recovery for 2007 of $8.2 million (2006 — expense of $20.9 million) under U.S. GAAP was allocated $6.0 million (2006 - $15.7 million) to corporate employees and $2.2 million (2006 - $5.2 million) to field employees.

As at December 31, 2007, total U.S. GAAP compensation cost related to trust unit rights non-vested and not recorded was $61.8 million (2006 - $45.6 million), which on a weighted average is expected to be charged to income over the next 2.7 years (2006 — 3.7 years). As at December 31, 2007, the fair value of trust units vested during the year was $9.4 million (2006 - $2.7 million) with a weighted average remaining life of 2.8 years (2006 — 3.3 years). If certain conditions are met, exercise prices are adjusted for distributions. Assuming these conditions are met, the total intrinsic value at December 31, 2007 for trust unit rights outstanding was $40.1 million (2006 - $95.2 million), for trust unit rights exercisable was $13.2 million (2006 - $14.0 million) and for trust units exercised during the period was $4.2 million (2006 - - $5.2 million).

A difference exists in the diluted weighted average number of trust units outstanding under U.S. GAAP as the unit-based compensation amount included is based on the fair value at each balance sheet date, compared to the fair value at only the date of grant under Canadian GAAP, leading to a change in the number of units included in the diluted calculation.

(e) Acquisitions

Petrofund

Penn West accounted for the Petrofund acquisition 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 acquisition had occurred on January 1, 2006, Penn West would have realized the following pro forma results for the year ended December 31, 2006:

(unaudited)		2006
Revenue ($CAD millions)	$	2,495.8
Net income ($CAD millions)		750.3
Basic net income per unit		3.18
Diluted net income per unit	$	3.15

(f) Additional disclosure

The Trust presents oil and natural gas revenues and royalty amounts prior to royalties in the Consolidated Statement of Income and Retained Earnings. Under U.S. GAAP, these items would be combined and presented net in the Consolidated Statement of Income and Retained Earnings.

Change in Accounting policies – US GAAP

Income Taxes

On January 1, 2007, the Trust adopted FASB 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. The adoption of FIN 48 did not have a material impact on our consolidated financial statements.

As at December 31, 2007, the total amount of the Trust's unrecognized tax benefits was approximately $8.7 million including $2.7 million of interest and penalties, which if recognized would affect the Trust's effective income tax rate. The resolution of these tax positions may take a number of years to complete with the appropriate tax authorities, thus fluctuations can occur from period to period. The amount of unrecognized tax benefits is not anticipated to significantly change within the next 12 months.

The Trust and its entities are subject to income taxation and related audits in the Canadian tax jurisdiction. The tax years from 2002 to 2007 remain open to examination in Canada.

Recent U.S. accounting pronouncements

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 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. Recently, FASB issued FSP FAS 157-2 delaying the effective date of SFAS 157 for non-financial assets and liabilities to fiscal years beginning after November 15, 2008. 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.

In December 2007, the FASB revised SFAS No. 141R, “Business Combinations”. This Statement outlines principles for the acquirer on recognizing assets and liabilities assumed in a transaction, establishes the acquisition date fair value for all assets and liabilities purchased and the requirement for additional disclosures for users of the financial statements to evaluate the business combination. The Statement is to be applied prospectively and becomes effective to business combinations at the beginning of the first annual reporting period on or after December 15, 2008. The Trust will implement this guidance on future business combinations on or after the effective date.

In December 2007, the FASB issued SFAS No. 160, “Non Controlling Interests in Consolidated Financial Statements”. This pronouncement required entities to report non-controlling interests as equity in the consolidated financial statements. The Statement is to be applied prospectively and becomes effective to

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business combinations at the beginning of the first annual reporting period on or after December 15, 2008. The Trust will implement this guidance, if applicable, on future acquisitions on or after the effective date.

SUPPLEMENTARY OIL AND GAS INFORMATION - FAS 69 (UNAUDITED)

The following disclosures in this section provide oil and gas information in accordance with the U.S. standard FAS 69, “Disclosure about Oil and Gas Producing Activities”.

NET PROVED OIL AND GAS RESERVES

Penn West engaged an independent qualified reserve evaluator, GLJ Petroleum Consultants Ltd. (“GLJ”), to review the Trust’s proved developed and proved undeveloped oil and gas reserves. As at December 31, 2007, all of Penn West’s oil and gas reserves are located in Canada. The changes in our net proved reserve quantities are outlined below.

Net reserves are Penn West royalty and working interest remaining reserves, less all Crown, freehold, and overriding royalties and interests that are not owned by Penn West.

Proved reserves are those estimated quantities of crude oil, natural gas and natural gas liquids that can be estimated with a high degree of certainty to be economically recoverable under existing economic and operating conditions. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Proved 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 (e.g. when compared to the cost of drilling a well) to put the reserves on production. Developed reserves may be subdivided into producing and non-producing.

Proved undeveloped reserves are those reserves that are expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production.

Penn West cautions users of this information as the process of estimating crude oil and natural gas reserves is subject to a level of uncertainty. The reserves are based on economic and operating conditions, therefore, changes can be made to future assessments as a result of a number of factors, which can include new technology, changing economic conditions and development activity.

YEAR ENDED DECEMBER 31, 2006
CONSTANT PRICES AND COSTS

Net Proved Developed and Proved Undeveloped Reserves (1)	Light and Medium Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	Natural gas Liquids (mbbl)	Barrels of Oil Equivalent (mboe)
December 31, 2005	124,051	45,217	466,854	9,580	256,657
Extensions & Discoveries	39	1,804	16,359	138	4,708
Improved Recovery	1,788	64	3,023	39	2,395
Technical Revisions	(2,418)	543	(6,078)	684	(2,205)
Acquisitions	57,050	621	221,473	4,291	98,874
Dispositions	(126)	(214)	(651)	(6)	(454)
Production	(10,884)	(6,435)	(87,789)	(1,165)	(33,116)
Change for the year	45,449	(3,617)	146,337	3,981	70,202
December 31, 2006	169,500	41,600	613,191	13,560	326,859
Developed	139,727	40,067	578,131	12,541	288,691
Undeveloped	29,773	1,533	35,060	1,019	38,168
Total (2)	169,500	41,600	613,191	13,560	326,859

YEAR ENDED DECEMBER 31, 2007
CONSTANT PRICES AND COSTS

Net Proved Developed and Proved Undeveloped Reserves (1)	Light and Medium Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	Natural gas Liquids (mbbl)	Barrels of Oil Equivalent (mboe)
December 31, 2006	169,500	41,600	613,191	13,560	326,859
Extensions & Discoveries	182	1,951	6,625	85	3,322
Improved Recovery	2,000	1,555	8,474	96	5,063
Technical Revisions	6,127	1,807	23,901	(51)	11,867
Acquisitions	10,452	1,088	28,211	407	16,649
Dispositions	(338)	(50)	(14,621)	(297)	(3,122)
Production	(13,632)	(7,190)	(90,489)	(1,803)	(37,707)
Change for the year	4,791	(839)	(37,899)	(1,563)	3,928
December 31, 2007	174,291	40,761	575,293	11,997	322,931
Developed	143,715	39,818	544,564	11,251	285,545
Undeveloped	30,576	943	30,729	746	37,386
Total (2)	174,291	40,761	575,293	11,997	322,931

(1) Columns may not add due to rounding.
(2) Penn West does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

CAPITALIZED COSTS

As at December 31, ($CAD millions)	2007	2006	2005
Proved oil and gas properties	$ 10,622	$ 9,379	$ 5,465
Unproved oil and gas properties	303	304	259
Total capital costs	10,925	9,683	5,724
Accumulated depletion and depreciation	3,511	2,644	2,009
Net capitalized costs	$ 7,414	$ 7,039	$ 3,715

COSTS INCURRED

For the years ended December 31, ($CAD millions)	2007	2006	2005
Property acquisition costs (1)			
Proved oil and gas properties	$ 422	$ 5	$ (6)
Unproved oil and gas properties	30	20	14
Exploration costs (2)	102	83	140
Development costs (3)	530	463	299
Capital Expenditures	1,084	571	447
Corporate acquisitions	21	3,323	—
Total Expenditures	$ 1,105	$ 3,894	$ 447

(1) Acquisitions are net of disposition of properties.
(2) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for exploration wells drilled.
(3) Includes equipping and facilities capital expenditures.

RESULTS OF OPERATIONS OF PRODUCING ACTIVITIES

For the years ended December 31, ($CAD millions)	2007	2006	2005
Oil and gas sales, net of royalties and commodity contracts	$ 1,827	$ 1,776	$ 1,561
Lease operating costs and capital taxes	536	441	342
Transportation costs	24	25	23
Depletion, depreciation and accretion	897	655	438
Income taxes (1)	—	—	54
Results of operations	$ 370	$ 655	$ 704

(1) Penn West is currently not taxable.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

The standardized measure of discounted future net cash flows is based on estimates made by GLJ of net proved reserves. Future cash inflows are computed based on year-end constant prices and cost assumptions applied against annual future production from proved crude oil and natural gas reserves. Future development and production costs are based on year-end constant price assumptions and assume the continuation of existing economic conditions. Future income taxes are calculated by applying statutory income tax rates. The Trust is currently not taxable. The standardized measure of discounted future net cash flows is computed using a 10 percent discount factor.

Penn West cautions users of this information that the discounted future net cash flows relating to proved oil and gas reserves are neither an indication of the fair market value of our oil and gas properties, nor of the future net cash flows expected to be generated from such properties.

The discounted future cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent is arbitrary and may not appropriately reflect future interest rates.

($CAD millions)	2007	2006
Future cash inflows	$ 21,597	$ 17,124
Future production costs	7,312	6,350
Future development costs	674	666
Undiscounted pre-tax cash flows	13,611	10,108
Future income taxes (1)	—	—
Future net cash flows	13,611	10,108
Less 10% annual discount factor	6,597	4,730
Standardized measure of discounted future net cash flows	$ 7,014	$ 5,378

(1) Penn West is currently not taxable.

($CAD millions)	2007	2006
Estimated future net revenue at beginning of year	$ 5,378	$ 4,972
Oil and gas sales during period net of production costs and royalties (1)	(1,475)	(1,277)
Changes due to prices and royalties related to forecast production (2)	2,037	(856)
Development costs during the period (3)	637	542
Changes in forecast development costs (4)	(617)	(544)
Changes resulting from extensions and improved recovery (5)	164	164
Changes resulting from discoveries (5)	18	4
Changes resulting from acquisitions of reserves (5)	362	1,907
Changes resulting from dispositions of reserves (5)	(68)	(7)
Discount factor (6)	538	497
Net change in income tax (7)	—	—
Changes resulting from technical reserves revision	258	(65)
All other changes (8)	(218)	41
Estimated future net revenue at end of year	$ 7,014	$ 5,378

(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 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 the conversion to a trust, Penn West does not pay income taxes.
(8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates and actual prices received versus forecast.

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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) 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

   (d) 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, 2008

/s/ William E. Andrew

William E. Andrew
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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) 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

   (d) 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, 2008

/s/ Todd Takeyasu

Todd Takeyasu
Executive Vice President 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, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William E. Andrew, 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
Chief Executive Officer of Penn West Petroleum Ltd.

March 26, 2008

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, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Todd Takeyasu, Executive 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
Executive Vice President and Chief Financial Officer of Penn West Petroleum Ltd.

March 26, 2008

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 auditors' report dated March 6, 2008 on the consolidated balance sheets of Penn West Energy Trust (the "Trust") as at December 31, 2007 and 2006 and the consolidated statements of income and retained earnings and cash flows for the years then ended;

- our audit report dated March 6, 2008 on the supplemental note to the consolidated financial statements entitled "Reconciliation of Canadian and United States Generally Accepted Accounting Principles";

- our Report of Independent Registered Public Accounting Firm dated March 6, 2008 on the Trust's internal control over financial reporting as of December 31, 2007.

each of which is contained in this annual report on Form 40-F of the Trust for the fiscal year ended December 31, 2007.

We also consent to the incorporation by reference of such reports in the Registration Statement (No. 333-145296) on Form F-3 of the Trust.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 26, 2008

KPMG LLP, a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

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. Joe, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

March 5, 2008

Penn West Petroleum Ltd.
2200, 425 First Street SW
Calgary AB T2P 3L8

Re: Consent of Independent Petroleum Consultants

To Whom it May Concern:

GLJ Petroleum Consultants consents to the use of its reports with respect to the reserves data of Penn West Energy Trust's: (i) Annual Report (Form 40-F) for the year ended December 31, 2007; (ii) Registration Statement on Form F-3 (Registration No. 333-145296), filed with the Securities and Exchange Commission; (iii) Fourth Quarter 2007 Press Release; (iv) Annual Information Form; and (v) Business Acquisition Report.

Sincerely,

GLJ PETROLEUM CONSULTANTS LTD.

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

Exhibit 99.11



R.K. Macleod*, B.S., P.Eng., *President*
H.J. Helwerda*, B.Sc., P.Eng., *Executive V.P.*
J.L. Chipperfield*, B.Sc., P.Geol., *Senior V.P.*
R.N. Johnson*, B.Sc., P.Eng., *V.P., Engineering*
D.W.C. Ho*, B.A.Sc., P.Eng., *V.P., Engineering*
G.D. Robinson*, B.Sc., P.Eng., *V.P., Engineering*
D.J. Carsted*, CD, B.Sc., P.Geol., *V.P., Geoscience*
K.P. McDonald, B.Comm., C.A., *Controller; Corporate Secretary*

M.W. Maughan, B.S., P.Geol., C.P.G., *V.P., Geoscience*
C.M.F. Galas, Ph.D., P.Eng., *Manager, Reservoir Studies*
R. Gerritse, B.Sc., *Manager, Systems*
B.F. Jose, M.Sc., P.Geoph., *Manager, Geoscience*
C.P. Six, B.Sc., P,Eng., *Manager, Engineering*
D.W. Woods, B.Ed., B.Sc., P.Eng., *Manager, Engineering*
D.R. Bates, B.Sc., P.Eng.
G.R. Finnis, B.Sc., P.Eng.
H.J. Firla, B.S., P.Eng.
K. Ghaffari, M.Sc., P.Eng.
J. Hanko, B.Sc., P.Geol.
P.B. Jung, B.S., P.Eng.
A. Kovaltchouk, M.Sc., P.Geol.

B.M. MacKinnon, B.Eng., P.Eng.
M.J. O'Blenes, M.Sc., P.Eng.
S.W. Pennell, B.Sc. Eng.
L.M. Precul, M.Sc., P.Eng.
G.I. Sanden, B.Sc., P.Eng.
M.W. Sargent, Ph.D., P.Geol.
V.V. Savenkov, M.Sc., MBA, P.Eng.
P.C. Sidey, B.Sc., P.Eng.
N.T. Stewart, B.A.Sc., P.Eng.
G.D. Strother-Stewart, B.Sc., P.Geol.
W.J. Waddell, B.Sc., P.Geol.
R.R. Warholm, B.Sc., P,Eng.
T.K. Wong, B.Sc., P.Geol.

**Directors*

Ref.: 1772

March 5, 2008

Penn West Petroleum Ltd.
2200, 425 First Street SW
Calgary AB T2P 3L8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

Sproule Associates Limited consents to the use of its reports with respect to the reserves data of Canetic Resources Trust and Vault Energy Trust incorporated by reference in Penn West Energy Trust's: (I) Annual Report (Form 40-F) for the year ended December 31, 2007; (ii) Registration Statement on Form F-3 (Registration No. 333-145296), filed with the Securities and Exchange Commission; (iii) Fourth Quarter 2007 Press Release; (iv) Annual Information Form; and (v) Business Acquisition Report.

Sincerely,

SPROULE ASSOCIATES LIMITED

/s/ Robert N. Johnson
Robert N. Johnson, P. Eng.
Vice-President Engineering

[Illegible]
for Harry J. Helwerda, P.Eng.
Executive Vice-President

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