UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

(Check One)

¨ 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, 2010

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 200, 207 – 9th Avenue SW, Calgary, Alberta, Canada T2P 1K3
(403) 777-2500
(Address and Telephone Number of Registrant's Principal Executive Offices)

DL Services Inc., Columbia Center, 701 Fifth Avenue, Suite 6100, Seattle, Washington 98104-7043 (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: **459,682,249**

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 ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ¨ No ¨

FORM 40-F

Explanatory Note

Effective January 1, 2011, Penn West Energy Trust (the "Trust") completed a reorganization transaction (the "Conversion") pursuant to which the Trust was converted into a corporation, Penn West Petroleum Ltd. ("PWPL"). As a result, pursuant to Rule 12g-3(g) under the United States Securities Exchange Act of 1934, as amended (the "Exchange Act"), this Annual Report on Form 40-F for the fiscal year ended December 31, 2010, is being filed on behalf of the Trust by PWPL, as successor registrant to the Trust under the Exchange Act. In this Annual Report on Form 40-F, unless the context requires otherwise, the term "Penn West" refers to the Trust prior to the completion of the Conversion and to PWPL following completion of the Conversion. Furthermore, where the context requires, the term "Penn West" refers herein to the Trust and PWPL collectively.

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, 2010;

(b) Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2010;

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2010; 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, 99.6, 99.7 and 99.8 to this Annual Report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the Penn West's fiscal year ended December 31, 2010, 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) under the Exchange Act) was carried out by the management 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. 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 (the "Commission") rules and forms and (ii) accumulated and communicated to the management of Penn West, including the CEO and CFO, 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, 2010. 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, 2010.

The effectiveness of Penn West's internal control over financial reporting as at December 31, 2010 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, 2010, 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, 2010, 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, 2010, there were no changes in Penn West's internal control over financial reporting that occurred during the fiscal year ended December 31, 2010 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 is 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 Directors, 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 shareholder 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 Directors, 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 such 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 2010 and 2009:

(CDN$)	**2010**	**2009**
Audit Fees	1,120,000	1,220,000
Audit-Related Fees	115,000	314,000
Tax Fees	-	9,155
All Other Fees	125,000	216,000
Total	1,360,000	1,759,155

Audit Fees. Audit fees consist of fees for the integrated audit of the 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 French translation services, long-form comfort letters related to the public offering of securities of Penn West, consultations related to International Financial Reporting Standards and matters related to the corporate acquisitions completed in 2010 and 2009.

Tax Fees. Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2009, the services provided in this category consisted of assistance and advice in relation to the taxability of certain amounts to employees and commodity taxes.

All Other Fees. All other fees primarily consisted of French translation services.

Pre-Approval Policies and Procedures.

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

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

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

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

Off-Balance Sheet Arrangements.

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

Tabular Disclosure of Contractual Obligations.

(CDN$ millions)

		Payment due by period			
Contractual Obligations	**Total**	**Less than 1 Year**	**1 to 3 Years**	**3 to 5 Years**	**More than 5 Years**
Transportation	89	30	37	22	-
Power Infrastructure	84	30	20	20	14
Drilling rigs	18	9	8	1	-
Purchase obligations (1)	68	13	26	21	8
Office lease (2)	865	71	134	121	539
Long term debt (3)(4)	2,496	-	778	311	1,407
Asset retirement obligations (5)	2,615	70	140	140	2,265
Total	**6,235**	**223**	**1,143**	**636**	**4,233**

(1) These amounts represent estimated commitments of $51 million for CO2 purchases and $17 million for processing fees related to interests in the Weyburn Unit.
(2) Future office lease commitments will be reduced by sublease recoveries of $413 million.
(3) Penn West’s syndicated bank facility is due for renewal on April 30, 2013. Penn West and its predecessor have successfully extended its credit facility on each renewal date since 1992.
(4) Interest payments have not been included since future debt levels and rates are not known at this time.
(5) 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 of directors, 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 of directors 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 of directors 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 under the Exchange Act. 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 and Frank Potter, members of Penn West's audit committee, each serve 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 or Mr. Potter's ability to effectively serve on Penn West's audit committee.

Communication with Non-Management Directors

Shareholders 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 Petroleum Ltd., 200, 207 – 9th Avenue SW, Calgary, Alberta, T2P 1K3 Canada. 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", which are available for viewing on Penn West's website at www.pennwest.com and are available in print to any shareholder 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, environment and regulatory committee are each available for viewing on Penn West's website at www.pennwest.com, and are available in print to any shareholder 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.

NYSE Statement of Governance Differences

As a Canadian corporation listed on the NYSE, Penn West is not required to comply with most of the NYSE corporate governance standards, so long as it complies with Canadian corporate governance practices. In order to claim such an exemption, however, Penn West must disclose the significant difference between its corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE's corporate governance standards. Penn West has included a description of such significant differences in corporate governance practices on its website which may be accessed at www.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 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 concurrently 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 Penn West.

SIGNATURES

Pursuant to the requirements of the Exchange Act, Penn West Petroleum Ltd., as successor to Penn West Energy Trust, 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 17, 2011.

Penn West Petroleum Ltd., as successor to Penn West Energy Trust

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, 2010
99.2	Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2010
99.3	Consolidated Financial Statements for the fiscal year ended December 31, 2010
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 PETROLEUM LTD.

Annual Information Form
for the year ended December 31, 2010

March 17, 2011

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APPENDIX A – RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Appendix A-1 – Report of Management and Directors on Reserves Data and Other Information
Appendix A-2 – Report on Reserves Data
Appendix A-3 – Statement of Reserves Data and Other Oil and Gas Information

APPENDIX B – MANDATE OF THE AUDIT COMMITTEE

GLOSSARY OF TERMS

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

"**6.5% Debenture Indenture**" means the trust indenture dated December 17, 2002 governing the 6.5% Debentures, as amended by the first supplemental trust indenture dated June 15, 2004, the second supplemental trust indenture dated January 5, 2006, the third supplemental trust indenture dated August 24, 2006, the fourth supplemental trust indenture dated January 11, 2008 and the fifth supplemental trust indenture dated January 1, 2011.

"**6.5% Debentures**" means our 6.5% convertible, extendible, unsecured, subordinated debentures issued on August 24, 2006 pursuant to the 6.5% Debenture Indenture.

"**7.2% Debenture Indenture**" means the trust indenture dated May 2, 2006 governing the 7.2% Debentures, as amended by the first supplemental trust indenture dated January 10, 2008 and the second supplemental trust indenture dated January 1, 2011.

"**7.2% Debentures**" means our 7.2% convertible, unsecured, subordinated debentures issued on May 2, 2006 pursuant to the 7.2% Debenture Indenture.

"**2007 Senior Notes**" means our notes in the aggregate principal amount of US$475 million issued on May 31, 2007, which consist 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 2007 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2008 Senior Notes** " means our notes in the aggregate principal amount of US$480 million and Cdn$30 million issued on May 29, 2008, which consist of US$153 million principal amount of 6.12 percent notes due in 2016, US$278 million principal amount of 6.30 percent notes due in 2018, Cdn$30 million principal amount of 6.16 percent notes due in 2018 and US$49 million principal amount of 6.40 percent notes due in 2020. The 2008 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2008 Senior Notes (Pounds Sterling)**" means our notes in the aggregate principal amount of £57 million issued on July 31, 2008, which consist of £57 million principal amount of 7.78 percent notes due in 2018. These notes bear interest at 7.78 percent in Pounds Sterling under the note purchase agreement, however, contracts were entered into that fix the interest rate at 6.95 percent in Canadian dollars. The 2008 Senior Notes (Pounds Sterling) are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2009 Senior Notes**" means our notes in the aggregate principal amount of US$154 million, £20 million, €10 million and Cdn$5 million issued on May 5, 2009, which consist of Cdn$5 million principal amount of 7.58 percent notes due in 2014, US$50 million principal amount of 8.29 percent notes due in 2014, US$35 million principal amount of 8.89 percent notes due in 2016, US$35 million principal amount of 8.89 percent notes due between 2013 and 2019, £20 million principal amount of 9.49 percent notes due in 2019, €10 million principal amount of 9.52 percent notes due in 2019 and US$34 million principal amount of 9.32 percent notes due in 2019. Contracts were entered into that fix the interest on the Pounds Sterling tranche of notes (9.49 percent in Pounds Sterling under the note purchase agreement) and Euro tranche of notes (9.52 percent in Euros under the note purchase agreement) in Canadian dollars at 9.15 percent and 9.22 percent, respectively. The 2009 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2010 Q1 Senior Notes**" means our notes in the aggregate principal amount of US$250 million and Cdn $50 million issued on March 16, 2010, which consist of US$27.5 million principal amount of 4.53 percent notes due in 2015, US$65 million principal amount of 5.29 percent notes due in 2017, US$112.5 million principal amount of 5.85 percent notes due in 2020, US$25 million principal amount of 5.95 percent notes due in 2022, US$20 million principal amount of 6.10 percent notes due in 2025, and Cdn$50 million principal amount of 4.88 percent notes due in 2015. The 2010 Q1 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2010 Q4 Senior Notes**" means our notes in the aggregate principal amount of US$170 million and Cdn $60 million issued on December 2, 2010 and January 4, 2011, which consist of US$18 million principal amount of 4.17 percent notes due in 2017, US$84 million principal amount of 4.88 percent notes due in 2020, US$18 million principal amount of 4.98 percent notes due in 2022, US$50 million principal amount of 5.23 percent notes due in 2025, Cdn$10 million principal amount of 4.44 percent notes due in 2015, and Cdn$50 million principal amount of 5.38 percent notes due in 2020. The 2010 Q4 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

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

"**Board**" or "**Board of Directors**" means the board of directors of Penn West.

"**Canadian GAAP**" means Canadian generally accepted accounting principles determined with reference to Part V of the Handbook, which contains the accounting principles applicable to public enterprises for periods relating to financial years beginning before January 1, 2011 (i.e., before the adoption of IFRS as Canadian GAAP for public enterprises).

"**Canetic**" means Canetic Resources Trust, which was terminated following the Canetic Acquisition.

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

"**Common Share**" means a common share issued by us.

"**Convertible Debentures**" means, collectively, the 6.5% Debentures and the 7.2% Debentures.

"**Corporate Conversion**" means the reorganization of Penn West Trust from a trust to a publicly traded exploration and production corporation, being Penn West, pursuant to a plan of arrangement completed under the ABCA effective January 1, 2011.

"**Debenture Indentures**" means, collectively, the 6.5% Debenture Indenture and the 7.2% Debenture Indenture.

"**Debenture Trustee**" means, in respect of the 6.5% Debentures, Computershare Trust Company of Canada, and in respect of the 7.2% Debentures, Canadian Western Trust Company.

"**Endev**" means Endev Energy Inc., a former subsidiary of Penn West that was amalgamated with Penn West Petroleum Ltd. subsequent to the Endev Acquisition.

"**Endev Acquisition**" means the plan of arrangement completed under the ABCA pursuant to which Penn West acquired Endev on July 22, 2008.

"**Engineering Reports**" means, collectively, the GLJ Report and the Sproule Report.

"**Form 40-F**" means our Annual Report on Form 40-F for the fiscal year ended December 31, 2010 filed with the SEC.

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

"**GLJ Report**" means the report prepared by GLJ dated January 28, 2011 evaluating approximately 47 percent of the crude oil, natural gas and natural gas liquids reserves of Penn West and the net present value of future net revenue attributable to those reserves effective as at December 31, 2010.

"**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.

"**Handbook**" means the Handbook of the Canadian Institute of Chartered Accountants, as amended from time to time.

"**IFRS**" means international financial reporting standards, being the standards and interpretations adopted by the International Accounting Standards Board, as amended from time to time. The changeover date to IFRS was January 1, 2011 with retrospective adoption from January 1, 2010 onwards. For periods relating to financial years beginning on or after January 1, 2011, Canadian generally accepted accounting principles applicable to publicly accountable enterprises is determined with reference to Part I of the Handbook, which is IFRS.

"**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 own.

"**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.

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

"**Penn West**", "**we**", "**us**" or "**our**" means: (i) subsequent to the completion of the Corporate Conversion, Penn West Petroleum Ltd., a corporation amalgamated under the ABCA pursuant to the Corporate Conversion and the successor to Penn West Trust; and (ii) prior to the completion of the Corporate Conversion, Penn West Trust. Where the context requires, these terms also include all of Penn West's Subsidiaries on a consolidated basis.

"**Penn West Partnership**" means Penn West Petroleum, a general partnership, the partners of which as at the date hereof are Penn West, Sifton Energy Inc. and Trocana Resources Inc.

"**Penn West Trust**" means Penn West Energy Trust, which trust was reorganized into Penn West and terminated pursuant to the Corporate Conversion.

"**Reece**" means Reece Energy Exploration Corp., a former subsidiary of Penn West that was amalgamated with Penn West Petroleum Ltd. effective January 1, 2010.

"**Reece Acquisition**" means the plan of arrangement completed under the ABCA pursuant to which Penn West acquired Reece on April 30, 2009.

"**SEC**" means the United States Securities and Exchange Commission.

"**Senior Notes**" means, collectively, our 2007 Senior Notes, our 2008 Senior Notes, our 2008 Senior Notes (Pounds Sterling), or 2009 Senior Notes, our 2010 Q1 Senior Notes and our 2010 Q4 Senior Notes.

"**Shareholders**" means holders of our Common Shares.

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

"**Sproule Report**" means the report prepared by Sproule dated February 11, 2011 evaluating approximately 43 percent and auditing approximately 10 percent of the crude oil, natural gas and natural gas liquids reserves of Penn West and the net present value of future net revenue attributable to those reserves effective as at December 31, 2010.

"**Subsidiaries**" has the meaning ascribed thereto in the *Securities Act* (Ontario) and, for greater certainty, includes all corporations and partnerships 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.

"**Trust Unit**" means a trust unit of Penn West Trust, all of which were exchanged for Common Shares on a one-for-one basis pursuant to the Corporate Conversion.

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

"**United States**" or "**U.S.**" means the United States of America.

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

"**U.S. GAAP**" means United States generally accepted accounting principles.

"**Vault**" means Vault Energy Trust, a former subsidiary of Penn West that was terminated pursuant to the Corporate Conversion.

"**Vault Acquisition**" means the plan of arrangement completed 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. On March 17, 2011, the exchange rate for U.S. dollars, expressed in Canadian dollars, based on the noon rate as reported by the Bank of Canada, was Cdn$1.00 equals US$0.9885.

All dollar amounts in this document are expressed in Canadian dollars, except where otherwise indicated. References to "**$**" or "**Cdn$**" are to Canadian dollars, references to "**US$**" are to United States dollars, references to "**£**" are to pounds sterling, and references to "**€**" are to Euros.

All financial information herein has been presented in Canadian dollars in accordance with Canadian GAAP, which differs from U.S. GAAP. A reconciliation of the principal differences between Penn West's financial results as at and for the years ended December 31, 2010 and 2009 calculated under Canadian GAAP and under U.S. GAAP is included in the Form 40-F.

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

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 million dollars.
MW	means megawatt.
MWh	means megawatt hour.
CO_2	means carbon dioxide.

OIL AND GAS INFORMATION ADVISORIES

Where any disclosure of reserves data is made in this Annual Information Form (including the Appendices hereto) that does not reflect all of the reserves of Penn West, 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.

All production and reserves quantities included in this Annual Information Form (including the Appendices hereto) have been prepared 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 Nevertheless, as part of Penn West's Annual Report on Form 40-F for the year ended December 31, 2010 filed with the SEC, Penn West has disclosed proved reserves quantities using the standards contained in SEC Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with the U.S. Financial Accounting Standards Board, "Disclosures About Oil and Gas Producing Activities", which disclosure complies with the SEC's rules for disclosing oil and gas reserves.

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, exploit and produce 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	0.948
MMbtu (at standard)	gigajoules	1.055
gigajoules (at standard)	Mcf	1.055

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

In the interest of providing our securityholders 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", "objective", "aim", "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: our dividend policy, including the amount of dividends that we intend to pay, the proposed timing of such payments, and the factors that may affect the amount of dividends that we pay; our belief that the various laws and regulations governing the oil and gas industry will not affect our operations in a manner materially different than other oil and gas companies of a similar size; our expectations regarding the operational and financial impact that climate change regulations in Alberta and British Columbia will have on us; our intention and ability to reduce our emissions intensity, improve energy efficiency and develop carbon dioxide injection and sequestration technology and infrastructure; the ability of our carbon dioxide injection pilot projects to provide information that could lead to much larger enhanced oil recovery projects with the potential to sequester significant volumes of carbon dioxide; our belief that the trend towards heightened standards in environmental legislation and regulation will continue and our expectation that we will be making increased expenditures as a result of the increasingly stringent laws relating to the protection of the environment; our assessment of the operational and financial impacts that certain risks factors could have on us and on our dividend policy and the value of our Common Shares should such risk factors materialize; the quantity of our oil, natural gas liquids and natural gas reserves, the recoverability thereof, and the net present values of future net revenue to be derived from our reserves using forecast prices and costs, including the disclosure set forth in Appendix A-3 under "Statement of Reserves Data and Other Oil and Gas Information – Reserves Data (Forecast Prices and Costs)"; our outlook for oil and natural gas prices; the amount of royalties, operating costs, development costs, abandonment and reclamation costs and income taxes that we will incur in connection with the production of our reserves; our expectations regarding how we will fund the development costs of our reserves; our expectation that interest and other funding costs will not make the development of any of our properties uneconomic; our expectations regarding future currency exchange rates and inflation rates; our expectations regarding the timing for developing our proved undeveloped reserves and probable undeveloped reserves and the amount of future capital expenditures required to develop such reserves; our expectations regarding the significant economic factors and other significant uncertainties that could affect our reserves data; the number of wells and facilities in respect of which we expect to incur abandonment and reclamation costs and the total amount of such costs that we expect to incur and the timing thereof; our exploration and development plans for our oil and natural gas properties in 2011 and beyond, including our anticipated 2011 capital expenditure levels in total and in each of our key resource plays and the key elements of our 2011 capital expenditure program (including the number of wells that we anticipate drilling on each of our key resource plays); our expectation regarding when we will be required to pay income taxes; our production volume estimates for 2011; the nature of, effectiveness of, and benefits to be derived from, our future marketing arrangements and risk management strategies;

With respect to forward-looking statements contained or incorporated by reference in this document, we have made assumptions regarding, among other things: the laws and regulations that we will be required to comply with, including laws and regulations relating to taxation, royalty regimes and environmental protection, and the continuance of those laws and regulations; future capital expenditure levels and capital programs; future oil, natural gas liquids and natural gas prices and differentials between light, medium and heavy oil prices; future oil and natural gas production levels; drilling results and the recoverability of our reserves; the amount of royalties, operating costs, development costs, abandonment and reclamation costs and income taxes that we will incur in connection with the production of our reserves; future exchange rates, inflation rates and interest rates; future income tax rates; the amount of tax pools available to us; the amount of future cash dividends 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 and the costs thereof; our ability to market our oil and natural gas successfully to current and new customers; our ability to reduce our exposure to commodity price fluctuations and counterparty risks through our risk management programs; 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, many of the forward-looking statements contained or incorporated by reference in this document are located proximate to assumptions that are specific to those forward-looking statements, and such assumptions should be taken into account when reading such forward-looking statements: see in particular the assumptions identified in Appendix A-3 under "Statement of Reserves Data and Other Oil and Gas Information – Reserves Data (Forecast Prices and Costs)" and "Statement of Reserves Data and Other Oil and Gas Information – Notes to Reserves Data Tables".

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 our 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: 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, including the historical acquisitions discussed herein; geological, technical, drilling and processing problems; general economic conditions in Canada, the U.S. and globally, and in particular, the effect that those conditions have on commodity prices and our access to capital; industry conditions, including fluctuations in the price of oil and natural gas; royalties payable in respect of our oil and natural gas production and changes thereto; 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 dispositions, acquisitions, joint ventures and partnerships, including the historical dispositions, acquisitions, joint ventures and partnerships discussed herein; changes in taxation and other laws and regulations that affect us and our securityholders; changes in government royalty frameworks in jurisdiction in which we operate and the impact that such changes may have on us; uncertainty of obtaining required approvals in respect of dispositions, acquisitions, joint ventures, partnerships and mergers; the potential failure of counterparties to honour their contractual obligations; 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.

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, 2010.

PENN WEST PETROLEUM LTD.

General

Penn West is a corporation amalgamated under the ABCA pursuant to the Corporate Conversion. It is the successor to Penn West Trust and commenced operations as such on January 1, 2011 under the trade name "Penn West Exploration". Penn West's head and registered office is located at Suite 200, 207 – 9th Avenue SW, Calgary, Alberta, T2P 1K3.

Corporate Conversion

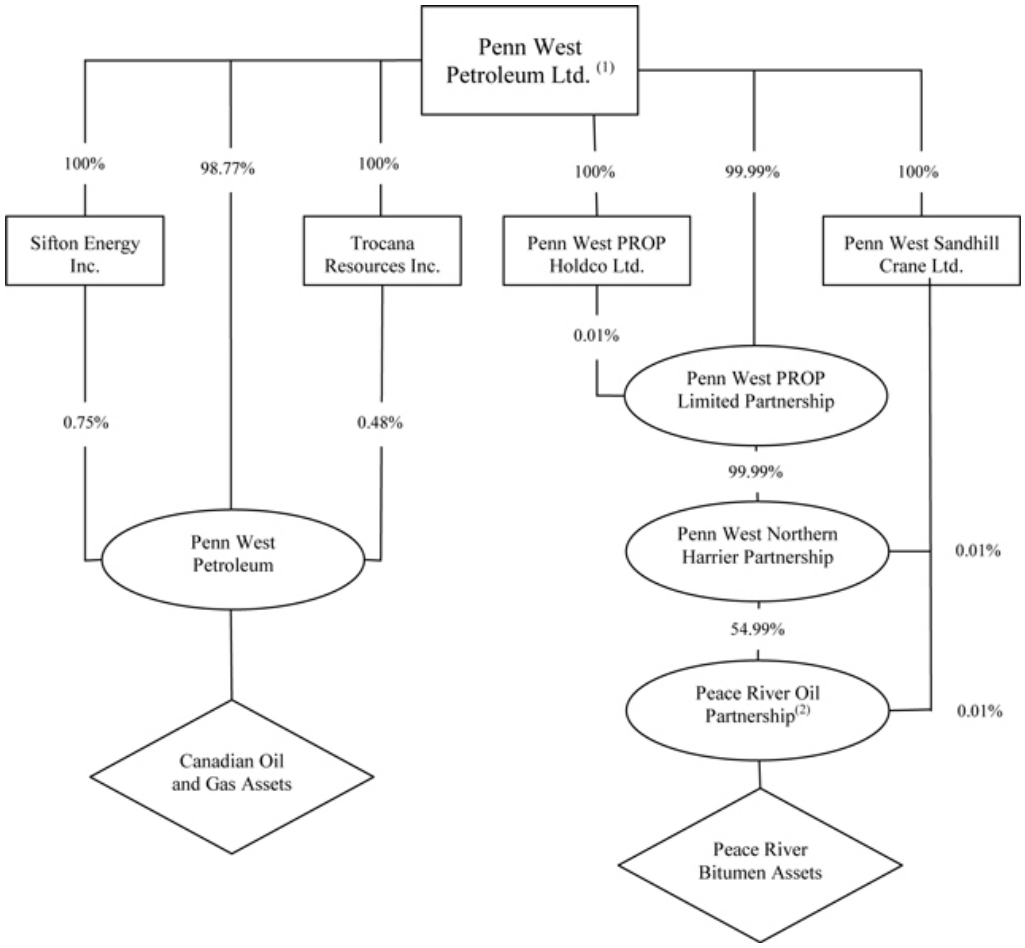
The Corporate Conversion was completed on January 1, 2011 and resulted in the reorganization of Penn West Trust (an income trust) into Penn West (a corporation) and the unitholders of Penn West Trust becoming the Shareholders of Penn West. Penn West and its Subsidiaries now carry on the business formerly carried on by Penn West Trust and its Subsidiaries. The Board of Directors and senior management of Penn West are comprised of the former members of the Board of Directors and senior management of the administrator of Penn West Trust.

In accordance with the terms of the Corporate Conversion, all of the outstanding Trust Units were exchanged for Common Shares on a one-for-one basis. In addition, as part of the Corporate Conversion, Penn West Trust was dissolved and, through a series of steps, Penn West acquired all of the assets of Penn West Trust and Penn West assumed all of the liabilities of Penn West Trust, including the Convertible Debentures, which are now Convertible Debentures of Penn West.

Our Common Shares and Convertible Debentures commenced trading on the TSX under the trading symbols "PWT", "PWT.DB.E" and PWT.DB.F" on January 10, 2011, and our Common Shares commenced trading on the NYSE under the trading symbol "PWE" on January 3, 2011.

Our Organizational Structure

The following diagram sets forth the organizational structure of Penn West and its material Subsidiaries as at the date hereof.



Notes:

(1) Penn West was formed pursuant to the amalgamation of Penn West Petroleum Ltd., 1566577 Alberta Ltd. and 960347 Alberta Ltd. effective January 1, 2011 pursuant to the Corporate Conversion.

(2) The remaining 45% interest in Peace River Oil Partnership is owned by Winter Spark Resources, Inc., an affiliate of China Investment Corporation.

(3) Each of the entities identified in the diagram is formed under the laws of the province of Alberta.

DESCRIPTION OF OUR BUSINESS

Overview

We are a Canadian exploration and production company actively engaged in the business of acquiring, exploring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets. We have historically focused on a balance of drilling on internally generated prospects and completing cost-effective acquisitions.

As at December 31, 2010, we had approximately 2,100 head office and field employees.

Reserves Data

See Appendices A-1, A-2 and A-3 for complete NI 51-101 oil and gas reserves disclosure for Penn West as at December 31, 2010.

General Development of the Business

The following is a description of the general development of our business over the last three completed financial years.

Year Ended December 31, 2008

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 trust unit of Vault, 0.14 of a Trust Unit for each one 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 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, Penn West acquired approximately 7 MMbbl of light/medium crude oil and NGLs and 56 Bcf of natural gas on a proved reserve basis, and approximately 10 MMbbl of light/medium crude oil and NGLs and 74 Bcf of natural gas on a proved plus probable reserve basis. Penn West also acquired approximately 125,000 net acres of undeveloped land.

In connection with the Vault Acquisition, Penn West also assumed approximately $89 million of bank indebtedness of Vault and approximately $99 million principal amount of convertible unsecured subordinated debentures of Vault (including the 7.2% Debentures, some of which continue to be outstanding at the date hereof).

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 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 $22 million was distributed to Canetic unitholders on January 15, 2008. As a result of the Canetic Acquisition, Penn West acquired approximately 89 MMbbl of light/medium crude oil and NGLs, 13 MMbbl of heavy oil and 408 Bcf of natural gas on a proved reserve basis, and approximately 120 MMbbl of light/medium crude oil and NGLs, 17 MMbbl of heavy oil and 564 Bcf of natural gas on a proved plus probable reserve basis. Penn West also acquired approximately 774,000 net acres of undeveloped land.

In connection with the Canetic Acquisition, Penn West assumed approximately $1.4 billion of bank indebtedness of Canetic and approximately $261 million principal amount of convertible unsecured subordinated debentures of Canetic (including the 6.5% Debentures, some of which continue to be outstanding at the date hereof).

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. This 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.

Endev Acquisition

Effective July 22, 2008, Penn West completed the Endev Acquisition pursuant to which Penn West acquired Endev on the basis of an exchange of 0.041 of a Trust Unit for each one (1) common share of Endev. An aggregate of approximately 3.6 million Trust Units were issued. As a result of the Endev Acquisition, Penn West acquired approximately 1,242 Mbbl of light/medium crude oil and NGLs, 56 Mbbl of heavy oil and 28,021 MMcf of natural gas on a proved reserve basis, approximately 1,900 Mbbl of light/medium crude oil and NGLs, 81 Mbbl of heavy oil and 40,760 MMcf of natural gas on a proved plus probable reserve basis, and approximately 98,580 net acres of undeveloped land. Penn West also assumed approximately $45 million of debt and working capital in connection with the Endev Acquisition.

Other Acquisitions and Dispositions

Penn West completed property dispositions, net of acquisitions, of approximately $50 million in 2008.

Private Placement of 2008 Senior Notes

Effective May 29, 2008, Penn West completed the private placement of the US$480 million and Cdn$30 million principal amount of 2008 Senior Notes, which consisted of the issuance of US$153 million principal amount of 6.12 percent notes due in 2016, US$278 million principal amount of 6.30 percent notes due in 2018, Cdn$30 million principal amount of 6.16 percent notes due in 2018 and US$49 million principal amount of 6.40 percent notes due in 2020. The 2008 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Private Placement of 2008 Senior Notes (Pounds Sterling)

Effective July 31, 2008, Penn West completed the private placement of the £57 million principal amount of 2008 Senior Notes (Pounds Sterling), which consisted of the issuance of £57 million principal amount of 7.78 percent notes due in 2018. The 2008 Senior Notes (Pounds Sterling) are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Year Ended December 31, 2009

Public Offering of Trust Units

On February 5, 2009, Penn West completed a public offering of 17.7 million Trust Units at a price of $14.10 per Trust Unit for aggregate gross proceeds of approximately $250 million. The net proceeds of the offering were used by Penn West to partially fund capital expenditures and to reduce its indebtedness. The Trust Units were issued by way of a prospectus supplement that was filed with securities regulatory authorities in Canada and the U.S. under Penn West's short form base shelf prospectus dated June 13, 2008 and SEC registration statement on Form F-10, which were previously filed with securities regulatory authorities across Canada and with the SEC under the multi-jurisdictional disclosure system.

Reece Acquisition

Effective April 30, 2009, Penn West completed the Reece Acquisition pursuant to which Penn West acquired Reece on the basis of an exchange of 0.125 of a Trust Unit for each one common share of Reece. An aggregate of approximately 4.7 million Trust Units were issued. As a result of the Reece Acquisition, Penn West added production of approximately 1,900 boe per day and approximately 67,000 net acres of undeveloped land. Penn West also assumed approximately $42 million of debt and working capital deficit in connection with the Reece Acquisition.

Private Placement of 2009 Senior Notes

Effective May 5, 2009, Penn West completed the private placement of the US$154 million, £20 million, €10 million and Cdn$5 million principal amount of 2009 Senior Notes, which consisted of the issuance of Cdn$5 million principal amount of 7.58 percent notes due in 2014, US$50 million principal amount of 8.29 percent notes due in 2014, US$35 million principal amount of 8.89 percent notes due in 2016, US$35 million principal amount of 8.89 percent notes due between 2013 and 2019, £20 million principal amount of 9.15 percent notes due in 2019, €10 million principal amount of 9.22 percent notes due in 2019 and US$34 million principal amount of 9.32 percent notes due in 2019. The 2009 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

November 2009 Asset Disposition

On November 30, 2009, Penn West completed the disposition (the "**November 2009 Asset Disposition**") of certain heavy oil assets located primarily in the Lloydminster area of Alberta and Saskatchewan. Pursuant to the transaction, Penn West disposed of approximately 6,000 boe per day of production and approximately 10,000 net acres of undeveloped land. The proceeds of the November 2009 Asset Disposition were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Other Acquisitions and Dispositions

Including the November 2009 Asset Disposition, Penn West completed property dispositions, net of acquisitions, of $369 million in 2009.

Year Ended December 31, 2010

Asset Exchange Agreement

On January 15, 2010, Penn West closed an asset exchange transaction (the "**Asset Exchange Transaction**") pursuant to which we increased our position in our light-oil resource plays in the Pembina and Dodsland areas. Penn West acquired production of approximately 560 boe per day and approximately 25,000 net acres of undeveloped land along with net cash proceeds of $434 million. In exchange, Penn West disposed of certain interests in the Leitchville area with approximately 3,500 boe per day of production. Funds received were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Private Placement of 2010 Q1 Senior Notes

Effective March 16, 2010, Penn West completed the private placement of the US$250 million and Cdn $50 million principal amount of 2010 Q1 Senior Notes, which consisted of the issuance of US$27.5 million principal amount of 4.53 percent notes due in 2015, US$65 million principal amount of 5.29 percent notes due in 2017, US$112.5 million principal amount of 5.85 percent notes due in 2020, US$25 million principal amount of 5.95 percent notes due in 2022, US$20 million principal amount of 6.10 percent notes due in 2025, and Cdn$50 million principal amount of 4.88 percent notes due in 2015. The 2010 Q1 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Renewal of Credit Facilities

On April 30, 2010, Penn West renewed its unsecured, revolving credit facility for a three-year term ending April 30, 2013 with a syndicate of 19 Canadian and international banks. The credit facility has an aggregate borrowing limit of $2.25 billion.

Joint Venture and Equity Financing with Affiliate of China Investment Corporation

On June 1, 2010, Penn West closed the formation of the Peace River Oil Partnership (" **PROP**") with Winter Spark Resources, Inc. (the " **CIC Affiliate**"), an affiliate of China Investment Corporation. PROP was formed to develop Penn West's bitumen assets located in the Peace River area of northern Alberta (the "**Peace River Assets**"). The Peace River Assets included approximately 237,000 net acres of oil sands leases and production of approximately 2,700 boe/d of bitumen and associated gas. Penn West contributed the Peace River Assets (valued at approximately $1.8 billion) to PROP and retained a 55 percent interest in PROP. The CIC Affiliate acquired a 45 percent interest in PROP by investing approximately $312 million in PROP (which was subsequently paid to Penn West by PROP to satisfy outstanding indebtedness of PROP to Penn West) and by committing to carry a portion of Penn West's share of PROP's future capital and operating expenses aggregating approximately an additional $505 million. Penn West serves as operator of PROP. Penn West also issued 23,524,209 Trust Units to the CIC Affiliate at a price of approximately $18.48 per Trust Unit for gross proceeds of approximately $435 million. The approximately $747 million of proceeds received upon closing were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Joint Venture with Affiliate of Mitsubishi Corporation

On September 23, 2010, Penn West closed the formation of a joint venture (the " **Cordova JV**") with an affiliate of Mitsubishi Corporation (the "**Mitsubishi Affiliate**"). The Cordova JV was formed to develop certain of Penn West's shale gas assets and conventional natural gas assets located in northeastern British Columbia (the "**Cordova Assets**"). Penn West sold the Mitsubishi Affiliate a 50 percent working interest in the Cordova Assets, which consisted of production of approximately 30 mmcf/d (gross) of conventional natural gas, approximately 550,000 acres (gross) of land (including approximately 120,000 acres (gross) of land prospective for shale gas in the Cordova Embayment), the Wildboy gas processing facility, the sales gas pipeline connecting the area to the TransCanada gathering system in Alberta, and all associated infrastructure. The Mitsubishi Affiliate paid Penn West approximately $250 million for its 50 percent working interest in the Cordova Assets and committed to fund approximately $600 million of the first $800 million of the Cordova JV's initial exploration and development capital expenditures. Penn West retained a 50 percent working interest in the Cordova Assets and serves as operator of the assets. The approximately $250 million of proceeds of the transaction were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Other Acquisitions and Dispositions

Including the Asset Exchange Transaction, the PROP transaction and the Cordova JV described above, Penn West completed property dispositions, net of acquisitions, of approximately $1,306 million in 2010.

Private Placement of 2010 Q4 Senior Notes

On December 2, 2010 and January 4, 2011, Penn West completed the private placement of the US$170 million and Cdn $60 million principal amount of 2010 Q4 Senior Notes, which consisted of the issuance of US$18 million principal amount of 4.17 percent notes due in 2017, US$84 million principal amount of 4.88 percent notes due in 2020, US$18 million principal amount of 4.98 percent notes due in 2022, US$50 million principal amount of 5.23 percent notes due in 2025, Cdn$10 million principal amount of 4.44 percent notes due in 2015, and Cdn$50 million principal amount of 5.38 percent notes due in 2020. The 2010 Q4 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

2011 Developments

Corporate Conversion

The Corporate Conversion was completed on January 1, 2011 and resulted in the reorganization of Penn West Trust (an income trust) into Penn West (a corporation) and the unitholders of Penn West Trust becoming the Shareholders of Penn West. Our Common Shares and Convertible Debentures commenced trading on the TSX under the trading symbols "PWT", "PWT.DB.E" and PWT.DB.F" on January 10, 2011, and our Common Shares commenced trading on the NYSE under the trading symbol "PWE" on January 3, 2011.

Ongoing Acquisition, Disposition, Farm-Out and Financing Activities

Potential Acquisitions

Penn West continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets as part of its on-going asset portfolio management program. Penn West is normally in the process of evaluating several potential acquisitions at any one time which individually or in the aggregate could be material. As of the date hereof, Penn West has not reached agreement on the price or terms of any potential material acquisitions. Penn West cannot predict whether any current or future opportunities will result in one or more acquisitions for Penn West.

Potential Dispositions and Farm-Outs

Penn West continues to evaluate potential dispositions of its petroleum and natural gas assets as part of its on-going portfolio asset management program. In addition, Penn West continues to consider potential farm-out opportunities with other industry participants in respect of its petroleum and natural gas assets in circumstances where Penn West believes it is prudent to do so based on, among other things, its capital program, development plan timelines and the risk profile of such assets. Penn West is normally in the process of evaluating several potential dispositions of its assets and farm-out opportunities at any one time, which individually or in the aggregate could be material. As of the date hereof, Penn West has not reached agreement on the price or terms of any potential material dispositions or farm-outs. Penn West cannot predict whether any current or future opportunities will result in one or more dispositions or farm-outs for Penn West.

Potential Financings

Penn West continuously evaluates its capital structure, liquidity and capital resources, and financing opportunities that arise from time to time. Penn West may in the future complete financings of Common Shares or debt (which may be convertible into Common Shares) for purposes that may include the financing of acquisitions, the financing of Penn West's operations and capital expenditures, and the repayment of indebtedness. As of the date hereof, Penn West has not reached agreement on the pricing or terms of any potential material financing. Penn West cannot predict whether any current or future financing opportunity will result in one or more material financings being completed.

Significant Acquisitions

Penn West did not complete an acquisition during its most recently completed financial year that was a significant acquisition for the purposes of Part 8 of National Instrument 51-102.

CAPITALIZATION OF PENN WEST

Share Capital

The authorized capital of Penn West consists of an unlimited number of Common Shares without nominal or par value and 90,000,000 preferred shares without nominal or par value. A description of the share capital of Penn West is set forth below. This description is a summary only. Shareholders are encouraged to read the full text of such share provisions, which are available on SEDAR at www.sedar.com.

Common Shares

The holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of the shareholders of Penn West (other than meetings of a class or series of shares of Penn West other than the Common Shares as such).

The holders of Common Shares are entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of Penn West ranking in priority to the Common Shares in respect of dividends.

The holders of Common Shares are entitled in the event of any liquidation, dissolution or winding-up of Penn West, whether voluntary or involuntary, or any other distribution of the assets of Penn West among its Shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of Penn West ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of Penn West ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of Penn West as are available for distribution.

As at March 17, 2011, 463,435,350 Common Shares were issued and outstanding.

Preferred Shares

The preferred shares may at any time or from time to time be issued in one or more series. Before any shares of a particular series are issued, the Board shall, by resolution, fix the number of shares that will form such series and shall, subject to the limitations set out in Penn West's articles, by resolution fix the designation, rights, privileges, restrictions and conditions to be attached to the preferred shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for securities of Penn West or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than preferred shares or payment in respect of capital on any shares in the capital of Penn West or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series, including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing, other than in the case of a failure to declare or pay dividends specified in any series of preferred shares, the voting rights attached to the preferred shares shall be limited to one vote per preferred share at any meeting where the preferred shares and Common Shares vote together as a single class.

As at the date hereof, no preferred shares are issued and outstanding.

Debt Capital

Penn West has issued the Senior Notes and originally assumed the Convertible Debentures pursuant to the Canetic Acquisition and the Vault Acquisition. In addition, Penn West has a syndicated credit facility. A description of the debt capital of Penn West is set forth below. This description is a summary only. Shareholders are encouraged to read the full text of the agreements governing Penn West's Convertible Debentures, Senior Notes and credit facility, which are available on SEDAR at www.sedar.com.

Convertible Debentures

Penn West has two series of convertible debentures outstanding, the 7.2% Debentures and the 6.5% Debentures. The following is a summary of the material attributes and characteristics of the Convertible Debentures.

The 7.2% Debentures were originally issued in the aggregate principal amount of $50 million and approximately $25 million principal amount was outstanding at March 17, 2011. The 7.2% Debentures mature on May 31, 2011.

The 6.5% Debentures were originally issued in the aggregate principal amount of $230 million and approximately $224 million principal amount was outstanding at March 17, 2011. The 6.5% Debentures mature on December 31, 2011.

Principal and Interest

The 7.2% Debentures bear interest from the date of issue at 7.2 percent per annum, which is payable semi-annually in arrears on May 31 and November 30 in each year. The 6.5% Debentures bear interest from the date of issue at 6.5 percent per annum, which is payable semi-annually in arrears on June 30 and December 31 in each year.

The principal amount of the Convertible Debentures is payable in lawful money of Canada or, at the option of Penn West and subject to applicable regulatory approval, by payment of Common Shares 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 the 6.5% Debentures, at the option of Penn West and subject to applicable regulatory approval, by the delivery to the Debenture Trustee of Common Shares in accordance with the Share Interest Payment Election described under "Interest Payment Option".

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

Conversion Privilege

The 7.2% Debentures are convertible at the holder's option into fully paid and non-assessable Common Shares 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 Common Share, being a conversion rate of approximately 13.3333 Common Shares for each $1,000 principal amount of 7.2% Debentures.

The 6.5% Debentures are convertible at the holder’s option into fully paid and non-assessable Common Shares 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% Debentures, at a conversion price of $51.5534 per Common Share, being a conversion rate of approximately 19.3974 Common Shares for each $1,000 principal amount of 6.5% Debentures.

Redemption and Purchase

Prior to maturity, the 6.5% Debentures may be redeemed in whole or in part from time to time at the option of Penn West on not more than 60 days and not less than 30 days prior notice, at a redemption price of $1,025 per 6.5% Debenture, plus accrued and unpaid interest thereon, if any.

Prior to maturity, Penn West may, on not more than 60 days and not less than 30 days prior notice, redeem the 7.2% Debentures at a price of $1,025 per 7.2% Debenture, plus accrued and unpaid interest thereon, if any.

Penn West 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, Penn West 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. Penn West 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 Common Shares to the holders of the Convertible Debentures. Any accrued and unpaid interest thereon will be paid in cash. The number of Common Shares 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 Common Shares on the date fixed for redemption or the maturity date, as the case may be. The term "**Current Market Price**" is defined in the Debenture Indentures to mean the weighted average trading price of the Common Shares 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 Penn West. "**Senior Indebtedness**" of Penn West 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 Penn West (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 Penn West 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 Penn West, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of Penn West, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of Penn West, 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 Penn West 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 Penn West, unless the Senior Indebtedness has been repaid in full.

The Convertible Debentures are effectively subordinate to claims of creditors of Penn West's Subsidiaries except to the extent Penn West 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 Penn West's credit facilities and to the prior payment in full of the Senior Notes.

Priority over Dividends

The Debenture Indentures provide that certain expenses of Penn West must be deducted in calculating the amount that may be paid to Shareholders as dividends. 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 dividends to Shareholders.

Change of Control of Penn West

Within 30 days following the occurrence of a change of control of Penn West involving the acquisition of voting control or direction over 66⅔ percent or more of the Common Shares (a "**Change of Control**"), Penn West 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 Penn West pursuant to the applicable Debenture Offer, Penn West will have the right and obligation to redeem all of the remaining Convertible Debentures of that series at the applicable Debenture Offer Price.

Interest Payment Option

Penn West may elect, from time to time, to satisfy its obligation to pay all or any part of the interest (the " **Interest Obligation**") on the 6.5% Debentures (but, for greater certainty, not the 7.2% Debentures), on the date it is payable under the 6.5% Debenture Indenture (an "**Interest Payment Date**"), by delivering sufficient Common Shares to the Debenture Trustee to satisfy all or such part, as the case may be, of the Interest Obligation in accordance with the 6.5% Debenture Indenture (the "**Share Interest Payment Election**"). The 6.5% Debenture Indenture provides that, upon such election, the Debenture Trustee shall: (a) accept delivery from Penn West of Common Shares; (b) accept bids with respect to, and consummate sales of, such Common Shares, each as Penn West 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 Common Shares not invested as aforesaid, to satisfy the Interest Obligation; and (d) perform any other action necessarily incidental thereto.

If a Share 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 Common Shares (plus any amount received by the Debenture Trustee from Penn West attributable to any fractional Common Shares) in full satisfaction of the Interest Obligation, and the holder of such Convertible Debentures will have no further recourse to Penn West 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 Penn West 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 Penn West specifying such default and requiring Penn West 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 such outstanding 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 66⅔ 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 66⅔ 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 Penn West shall not issue additional convertible debentures of equal ranking if the principal amount of all issued and outstanding convertible debenture of Penn West exceeds 25 percent of the Total Market Capitalization of Penn West immediately after the issuance of such additional convertible debentures. "**Total Market Capitalization**" is defined in the Debenture Indentures as the total principal amount of all issued and outstanding convertible debentures of Penn West which are convertible at the option of the holder into Common Shares plus the amount obtained by multiplying the number of issued and outstanding Common Shares by the Current Market Price of the Common Shares on the relevant date.

Book-Entry System for Convertible Debentures

The Convertible 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 are evidenced by a single book-entry only certificate. Registration of interests in and transfers of the Convertible Debentures is made only through the depository service of CDS & Co.

Senior Notes and Credit Facility

Penn West has issued the Senior Notes, which consist of US$1,529 million principal amount of notes, Cdn$145 million principal amount of notes, £77 million principal amount of notes and €10 million principal amount of notes. The Senior Notes are unsecured and rank equally with our bank credit facilities.

Penn West has an unsecured, revolving credit facility with a three-year term ending April 30, 2013 with a syndicate of 19 Canadian and international banks. The credit facility has an aggregate borrowing limit of $2.25 billion. As at March 17, 2011, approximately $0.9 billion had been borrowed under the credit facility.

For additional information regarding our Senior Notes and our credit facility, see Notes 7 and 20 (the "**Notes**") to our audited consolidated financial statements for the year ended December 31, 2010, and "Financing" and "Liquidity and Capital Resources" in our related management's discussion and analysis (collectively, the "**MD&A Disclosure**"), both of which are available on SEDAR at www.sedar.com. The Notes and the MD&A Disclosure are both incorporated by reference into this Annual Information Form.

Ratings

Penn West has neither asked for nor received a stability rating or credit 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.

DIRECTORS AND EXECUTIVE OFFICERS OF PENN WEST

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 Penn West, together with their principal occupations during the last five years. The directors of Penn West will hold office until the next annual meeting of Shareholders or until their respective successors have been duly elected or appointed.

Name, Province/State and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
James E. Allard[1][2] Alberta, Canada	Director since June 30, 2006	Independent director and business advisor.
William E. Andrew Alberta, Canada	Chief Executive Officer Director since June 3, 1994	Chief Executive Officer of Penn West since January 11, 2008. Prior thereto, President and Chief Executive Officer of Penn West since May 2005.
Robert G. Brawn[4][5] Alberta, Canada	Director since January 11, 2008	President of 738831 Alberta Ltd. (a private investment company) since 2003.
George H. Brookman[2][4] Alberta, Canada	Director since August 3, 2005	Chief Executive Officer of West Canadian Industries Group Inc. (a digital printing and document management company).
John A. Brussa Alberta, Canada	Chairman of the Board of Directors Director since April 21, 1995	Senior Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Daryl Gilbert[3][5] Alberta, Canada	Director since January 11, 2008	Independent businessman since 2005 and Managing Director of JOG Capital Inc. (a private equity investment management company) since 2008.
Shirley A. McClellan[1][5] Alberta, Canada	Director since June 8, 2007	Chancellor of the University of Lethbridge since February 2011. Distinguished Scholar in Residence at the University of Alberta for the Faculties of Agriculture and Rural Economy and the School of Business since September 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.
Murray R. Nunns Alberta, Canada	President and Chief Operating Officer Director from May 27, 2005 to January 11, 2008 and director since June 9, 2009	President and Chief Operating Officer of Penn West since February 8, 2008. Prior thereto, director of Penn West and Executive Chairman of Monterey Exploration Ltd., a public oil and gas company.
Frank Potter[1][4] Ontario, Canada	Director since June 30, 2006	Independent director for a number of public, private and not-for-profit corporations.
R. Gregory Rich[2] [3] [4] Texas, United States	Director since January 11, 2008	Principal of Blackrock Energy Associates (an energy consulting and investment firm) since October 2002.

Name, Province/State and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
Jack Schanck[3][5] Alberta, Canada	Director since June 2, 2008	Since December 2010, President, Chief Executive Officer and director of Sonde Resources Corp. (an Alberta-based oil and natural gas exploration company). Prior thereto, an independent businessman from January 2010 to December 2010. Managing Partner of Tecton Energy, LLC (a Texas-based oil and natural gas exploration and production company) from 2007 to 2009. Prior thereto, Chief Executive Officer of SouthView Energy LLC (an oil and natural gas investment company) from 2005 to 2007.
James C. Smith[1][2][3] Alberta, Canada	Director since May 31, 2005	Independent director and consultant to a number of public and private oil and gas companies.
Mark P. Fitzgerald Alberta, Canada	Senior Vice President, Production	Senior Vice President, Production of Penn West since November 3, 2008. Prior thereto, Senior Vice President, Engineering of Penn West since January 11, 2008. Prior thereto, Vice President, Operations of Canetic since January 2006.
Hilary Foulkes Alberta, Canada	Executive Vice President, Business Development	Executive Vice President, Business Development of Penn West since January 1, 2011. Prior thereto, Senior Vice-President, Business Development of Penn West since April 29, 2008. Prior thereto, a Managing Director with the investment banking firm, Scotia Waterous for eight years.
Thane A.E. Jensen Alberta, Canada	Senior Vice President, Operations Engineering	Senior Vice President, Operations Engineering of Penn West since November 3, 2008. Prior thereto, Senior Vice President, Exploration and Development of Penn West since 2005.
S. Keith Luft Alberta, Canada	General Counsel and Senior Vice President, Stakeholder Relations	General Counsel and Senior Vice President, Stakeholder Relations of Penn West since February 8, 2008. Prior thereto, Senior Vice President, Stakeholder Relations of Penn West since January 11, 2008. Prior thereto, Vice President, Land and Legal of Penn West since 2006.
David W. Middleton Alberta, Canada	Executive Vice President, Managing Director, Peace River Oil Partnership	Executive Vice President, Managing Director, Peace River Oil Partnership since June 1, 2010. Prior thereto, Executive Vice President, Engineering and Corporate Development of Penn West since November 3, 2008. Prior thereto, Executive Vice President, Operations and Corporate Development of Penn West since February 8, 2008. Prior thereto, Chief Operating Officer of Penn West since January 11, 2008. Prior thereto, Executive Vice President and Chief Operating Officer of Penn West since 2005.

Name, Province/State and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
Bob Shepherd Alberta, Canada	Senior Vice President, Exploration and Development	Senior Vice President, Exploration and Development of Penn West since October 1, 2009. Prior thereto, Vice President, Exploitation of Penn West, since January 22, 2009. Prior thereto, President of Laser Energy Inc. since 2007. Prior thereto, General Manager, Oil Sands of Husky Oil Operations Ltd. since 2004.
Todd H. Takeyasu Alberta, Canada	Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer of Penn West since February 8, 2008. Prior thereto, Senior Vice President, Finance – Treasury of Penn West since January 11, 2008. Prior thereto, Senior Vice President and Chief Financial Officer of Penn West since 2006.

Notes:

(1) Member of the Audit Committee of the Board of Directors.
(2) Member of the Human Resources and Compensation Committee of the Board of Directors.
(3) Member of the Reserves Committee of the Board of Directors.
(4) Member of the Governance Committee of the Board of Directors.
(5) Member of the Health, Safety, Environment and Regulatory Committee of the Board of Directors.

As at March 17, 2011, the directors and executive officers of Penn West, as a group, beneficially owned, or controlled or directed, directly or indirectly approximately 1.2 million Common Shares, or less than one percent of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the knowledge of Penn West, except as otherwise disclosed herein, no director or executive officer of Penn West (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 Penn West), 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 was 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 the *Companies' Creditors Arrangement Act* (Canada) in June 2007, and after a failed restructuring effort a receiver was appointed by one of the company's lenders in December 2007. The company has since ceased operations and is delisted.

To the knowledge of Penn West, except as otherwise disclosed herein, no director or executive officer of Penn West (nor any personal holding company of any of such persons), or a 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 Penn West) 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 in 2002. 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.

To the knowledge of Penn West, no director or executive officer of Penn West (nor any personal holding company of any of such persons), or a 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 Directors, Officers and Senior Financial Management (the "**Codes**"). In general, the private investment activities of employees, directors and officers are not prohibited; however, should an existing investment pose a potential conflict of interest, the potential conflict is required by the Codes to be disclosed to the President, 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 an 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 Penn West should be a director or officer of any entity engaged in the oil and gas business unless expressly authorized by the Board of Directors. Any director of Penn West who is actively engaged in the management of, or who owns an investment of one per cent or more of the outstanding shares, in public or private entities shall disclose such holding to the Board of Directors. In the event that any circumstance should arise as a result of such positions or investments being held or otherwise which in the opinion of the Board of Directors constitutes a conflict of interest which reasonably affects such person's ability to act with a view to the best interests of 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.

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.

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 B 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 or her responsibilities as an Audit Committee member.

James C. Smith (Chairman)

Mr. Smith is a Chartered Accountant with over 39 years of experience in public accounting and industry. Since 1998, he has been a business consultant and independent director to a number of public and private companies operating in the oil and natural gas industry. From February 2002 to June 2006, he served as the Vice-President and Chief Financial Officer of Mercury Energy Corporation, a private oil and natural gas company. Mr. Smith also held the position of Chief Financial Officer of Segue Energy Corporation, a private oil and natural gas company, from January 2001 to August 2003. 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. Mr. Smith served as the Vice-President and Chief Financial Officer of Crestar Energy Inc. from its inception in 1992 until 1998, during which time the company completed an initial public offering, was listed on the TSX and completed several major debt and equity financing transactions.

James E. Allard

Mr. Allard is an independent director and business advisor. He has a 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 42 years, during which time he has served as the Chief Executive Officer, Chief Financial Officer and/or a director of a number of publicly traded and private companies. Over the past ten years he has served on the board of the Alberta Securities Commission, acted as the sole external trustee and advisor to a mid-sized pension plan and served as a director and advisor to several companies. From 1981 to 1995, Mr. Allard served as a senior executive officer of Amoco Corporation and as a director of Amoco Canada, which at that time was Canada's largest natural gas producer.

Frank Potter

Mr. Potter has a background in international banking in Europe, the Middle East and the United States. He managed the international business of one of Canada's principal banks before being appointed Executive Director of the World Bank in Washington where he served for nine years. Mr. Potter subsequently served as a Senior Advisor at the Department of Finance for the Canadian government. Mr. Potter serves on a number of boards, including Canadian Tire Corporation Limited and the Royal Ontario Museum.

Shirley A. McClellan

Mrs. McClellan is a Distinguished Scholar in Residence at the University of Alberta for the Faculties of Agriculture and Rural Economy and the School of Business. She lectures primarily in Rural Economy and the School of Business. Mrs. McClellan brings to Penn West the experience gained over 20 years of distinguished service to the Province of Alberta. Her career included 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 Government of Alberta. Mrs. McClellan 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 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.

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 table summarizes the fees paid by Penn West to KPMG LLP for external audit and other services during the periods indicated.

Year	Audit Fees[1] ($)	Audit Related Fees[2] ($)	Tax Fees[3] ($)	All Other Fees[4] ($)
2010	1,120,000	115,000	-	125,000
2009	1,220,000	314,000	9,155	216,000

Notes:

(1) 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.

(2) 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 in note (1)). The services comprising the fees disclosed under this category principally consisted of French translation services, long-form comfort letters related to the public offering of Trust Units in 2009, consultations related to International Financial Reporting Standards and matters related to the corporate acquisitions completed in 2010 and 2009.

(3) 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. The services comprising the fees disclosed under this category principally consisted of assistance and advice in relation to the taxability of certain amounts paid to employees and in relation to commodity taxes.

(4) 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". The services comprising the fees disclosed under this category principally consisted of French translation services.

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 Penn West.

DIVIDENDS AND DIVIDEND POLICY

Dividend Policy

Following the completion of the Corporate Conversion, the Board of Directors adopted a quarterly dividend policy with an initial dividend rate of Cdn$0.27 per Common Share, which will be paid on or about the 15th day of the month that follows the end of each quarter to Shareholders of record at the end of such quarter. The first quarterly dividend of Penn West to be paid following the Corporate Conversion has been declared payable on April 15, 2011 to Shareholders of record on March 31, 2011.

Notwithstanding the foregoing, the amount of future cash dividends, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreement to which Penn West is a party from time to time (including, without limitation, the agreements governing Penn West's credit facilities and Senior Notes), and the satisfaction of liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board intends to review Penn West's dividend policy on a quarterly basis. **Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of our Board and management team, the Board may change our dividend policy following any such quarterly review or at any other time that the Board deems appropriate, and as a result, future cash dividends could be reduced or suspended entirely. The market value of our Common Shares may deteriorate if we reduce or suspend the amount of cash dividends that we pay in the future and such deterioration may be material.** See "*Risk Factors*".

Effective from January 1, 2011, all dividends paid on our Common Shares will be designated as "eligible dividends" for Canadian income tax purposes. This designation will apply until we notify Shareholders otherwise. Shareholders seeking further information regarding the taxation of "eligible dividends" should contact their Canadian tax advisor.

The credit agreement governing our syndicated credit facility and each of the note purchase agreements governing our Senior Notes contain provisions which restrict our ability to pay dividends to Shareholders in the event of the occurrence of certain events of default. The full text of the agreements governing our credit facility and our Senior Notes is available on SEDAR at www.sedar.com. For additional information regarding our credit facility and our Senior Notes, see Notes 7 and 20 (the "**Notes**") to our audited consolidated financial statements for the year ended December 31, 2010, and "Financing" and "Liquidity and Capital Resources" in our related management's discussion and analysis (collectively, the "**MD&A Disclosure**"), both of which are available on SEDAR at www.sedar.com. The Notes and the MD&A Disclosure are both incorporated by reference into this Annual Information Form.

Dividend Reinvestment and Optional Common Share Purchase Plan

Our Dividend Reinvestment and Optional Common Share Purchase Plan (the " **DRIP**") provides eligible Shareholders with the advantage of acquiring additional Common Shares by reinvesting their dividends. At our discretion, Common Shares will be acquired with dividends either on the TSX at prevailing market rates or from treasury at 95% of the "**average market price**" (as defined in the DRIP). Generally, we expect to issue Common Shares from treasury at a discount to satisfy the dividend reinvestment component of the DRIP.

Eligible Shareholders may also make optional cash payments of a minimum of $500 up to a maximum of $15,000 per quarter to purchase additional Common Shares. Shares purchased with optional cash payments will be acquired either on the TSX at prevailing market rates or from treasury at the average market price (without a discount).

We will determine prior to each dividend payment date the number of Common Shares, if any, that will be made available from treasury under the DRIP on such payment date. No assurances can be made that Common Shares will be made available from treasury on a regular basis, or at all.

Shareholders who are residents of Canada are eligible to participate in the dividend reinvestment component of the DRIP and to purchase new Common Shares with optional cash payments. Shareholders who are resident in the United States are eligible to participate in the dividend reinvestment component of the DRIP. United States residents are not eligible to make optional cash payments to purchase additional Common Shares pursuant to the DRIP. With the exception of the foregoing, unless otherwise announced by us, Shareholders who are not residents of Canada are not entitled to participate, directly or indirectly, in the DRIP.

Distributions Paid to Unitholders of Penn West Trust

During the three most recently completed financial years, Penn West Trust paid the following amount of cash distributions per Trust Unit:

Month	2010 ($)	2009 ($)	2008 ($)
January	0.15	0.34	0.34
February	0.15	0.23	0.34
March	0.15	0.23	0.34
April	0.15	0.23	0.34
May	0.15	0.15	0.34
June	0.15	0.15	0.34
July	0.15	0.15	0.34
August	0.15	0.15	0.34
September	0.15	0.15	0.34
October	0.09	0.15	0.34
November	0.09	0.15	0.34
December	0.09	0.15	0.34
Total	1.62	2.23	4.08

MARKET FOR SECURITIES

Common Shares and Trust Units

Following the completion of the Corporate Conversion, the Common Shares were listed on the TSX under the symbol PWT on January 10, 2011 and on the NYSE under the symbol PWE on January 3, 2011. Prior thereto, the Trust Units were 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 the Trust Units in 2010 as reported by the TSX and the NYSE.

	TSX		
Period	Unit price ($) High	Unit price ($) Low	Volume
January	19.47	17.44	14,232,894
February	21.57	17.65	21,308,547
March	22.35	20.56	22,029,064
April	22.33	19.68	19,007,959
May	20.60	17.09	28,390,926
June	21.85	19.36	23,235,589
July	20.98	19.86	14,465,015
August	20.77	19.65	17,084,792
September	20.85	18.30	31,215,151
October	23.50	20.51	22,900,492
November	23.96	21.80	29,357,502
December	24.45	21.78	24,768,987

	NYSE		
Period	Unit price (US$) High	Unit price (US$) Low	Volume
January	18.88	16.30	37,829,723
February	20.51	16.54	47,370,654
March	21.81	20.07	38,786,842
April	22.32	19.52	40,555,257
May	20.32	16.00	64,017,583
June	21.49	18.36	36,179,116
July	20.35	18.83	28,066,146
August	20.09	18.70	28,588,156
September	20.33	17.71	44,924,418
October	22.89	19.98	48,711,298
November	23.95	21.28	36,531,023
December	24.33	21.62	34,721,180

7.2% Debentures

The 7.2% Debentures trade on the TSX under the symbol "PWT.DB.E". The following table sets forth certain trading information for our 7.2% Debentures in 2010 as reported by the TSX (with each unit of volume traded being equal to $100 principal amount of 7.2% Debentures).

	TSX		
Period	Debenture price ($) High	Debenture price ($) Low	Volume
January	103.00	100.20	2,520
February	103.01	102.11	1,940
March	104.30	103.06	19,060
April	103.50	102.66	4,050
May	102.65	101.75	2,320
June	103.75	102.35	1,980
July	103.00	102.51	1,100
August	102.66	102.55	670
September	103.49	102.50	1,800
October	103.48	102.51	1,950
November	103.00	102.06	2,020
December	102.11	101.76	2,695

6.5% Debentures

The 6.5% Debentures trade on the TSX under the symbol "PWT.DB.F". The following table sets forth certain trading information for our 6.5% Debentures in 2010 as reported by the TSX (with each unit of volume traded being equal to $100 principal amount of 6.5% Debentures).

	TSX		
Period	Debenture price ($) High	Debenture price ($) Low	Volume
January	104.00	101.00	117,023
February	104.50	102.31	13,930
March	104.00	102.60	20,870
April	103.50	102.05	19,660
May	104.00	101.75	28,950
June	103.50	101.80	17,025
July	103.50	102.50	14,520
August	103.26	102.50	19,490
September	104.00	102.98	21,930
October	103.80	103.11	22,650
November	103.70	102.01	15,120
December	103.25	102.10	19,920

Other than incentive securities issued pursuant to Penn West's equity compensation plans and the Senior Notes, 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 and except in respect of incentive securities issued pursuant to Penn West's equity compensation plans).

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural 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

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. 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 a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as Alberta Nova Inventory Transfer rather than through direct 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 propane, butane and ethane) exports for a term of less than two years or for a term of two 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 for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and 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. At present, Manitoba does not have natural gas production in commercial quantities and does not therefore impose such export restrictions.

Pipeline Capacity

Although pipeline expansions are ongoing, transport restrictions can occur from time to time which could potentially impede the access of our products to market.

The North American Free Trade Agreement

The North American Free Trade Agreement (" **NAFTA**") among the governments of Canada, the United States 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 the total supply of goods of the party maintaining the restriction as compared to 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 measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province 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 negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of 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 or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (" **NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF ranged from 0 to 50 percent, an increase from the previous maximum rates of 30 to 35 percent depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40 percent. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/$m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5 to 50 percent, an increase from the previous maximum rates of 5 to 35 percent, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 36 percent. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1 to 9 percent depending on the market price of oil: rates are 1 percent when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9 percent when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1 to 9 percent and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25 percent and increase for every dollar of market price of oil increase above $55 up to 40 percent when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the " **IETP**"), which has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques, and improving the recovery of natural gas from coal seams. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5 percent royalty rate for the first 12 months of production on a maximum of 50,000 bbls of oil or 500 MMcf of natural gas. In June 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5 percent for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5 percent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and 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 calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10 percent of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23 percent of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spud between December 1, 2003 and September 1, 2009;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the " **Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50 percent of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In both 2009 and 2010, the Government of British Columbia allocated $120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2 percent royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15 percent and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "**heavy oil**", "**southwest designated oil**" or "**non-heavy oil other than southwest designated oil**". The conventional royalty and production tax classifications ("**fourth tier oil**", "**third tier oil**", "**new oil**" and "**old oil**") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier oil, 10 percent for heavy oil that is third tier oil or new oil, 12.5 percent for southwest designated oil that is third tier oil or new oil, 15 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20 percent for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30 percent for all fourth tier oil, 25 percent for heavy oil that is third tier oil or new oil, 35 percent for southwest designated oil that is third tier oil or new oil, 35 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45 percent for old oil.

The amount payable as a royalty in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "**non-associated gas**" or "**associated gas**" and royalty rates are determined according to the finished drilling date of the respective well. 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. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier gas, 15 percent for third tier or new gas, and 20 percent for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30 percent for all fourth tier gas, 35 percent for third tier and new gas, and 45 percent for old gas**.**

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre-payout and post-payout; and

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1 percent of gross revenues on enhanced oil recovery projects pre-payout and 20 percent post-payout and a freehold production tax of nil on operating income from enhanced oil recovery projects pre-payout and 8 percent post-payout.

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

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as " **old oil**" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "**new oil**" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "**third tier oil**" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "**holiday oil**" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5 percent of the volume of natural gas sold.

Producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2 percent of the volume sold. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the " **Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area.

The Program consists of the following components:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume to a maximum of 10,000 m^3;

- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of 20,000 m^3, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m^3 of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;

- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m^3, ar a horizontal leg drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 will earn an additional holiday royalty volume of 3,000 m^3;

- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m^3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m^3 per operating day; and

- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection.

Further, holiday oil volumes earned by a newly drilled well or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments, with the exception of Manitoba, where approximately 80 percent of the crude oil and natural gas rights in the portion of the province in which hydrocarbons are known to exist are privately owned. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms 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.

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Alberta

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land, and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol (" **Kyoto Protocol** "), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG levels to 6 percent below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "**Existing Facilities**" and "**New Facilities**". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18 percent below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2 percent. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25 percent or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2 percent emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be: (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d per company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, which is discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets.

1. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also 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 GHG 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 described above.

2. 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 purchase the offset credits for cancellation or banking for future use or sale.

3. Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. 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.

4. Finally, a one-time credit of up to 15 million tonnes 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.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Furthermore, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July 2011 and for refineries by December 2011.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50 percent reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "**Established Facilities**" and "**New Facilities**". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, and 10% of their baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

We do not operate any facilities in Alberta that are covered by the CCEMA and the *Specified Gas Emitters Regulation*. However, we do have minor working interests in non-operated facilities that are subject to the CCEMA and the *Specified Gas Emitters Regulation*. As at the date hereof, we do not believe that our financial obligations associated with such non-operated facilities are material.

Facilities in Alberta that have GHG emissions between 50,000 and 100,000 tonnes per year are required to report under the *Specified Gas Reportin Regulation*. Penn West anticipates it will have one operated facility that will be required to report under these regulations. As at the date hereof, we do not believe that our financial obligations associated with such reporting obligations are material.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO_2 equivalent and rose to $15 per tonne of CO_2 equivalent on July 1, 2009 and $20 per tonne of CO_2 equivalent on July 1, 2010. It is scheduled to further increase at a rate of $5 per tonne of CO_2 equivalent on July 1 of every year until it reaches $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax. In 2010, the amount of carbon tax paid by us pursuant to this legislation with respect to our operated and non-operated properties in British Columbia was not material to us.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. It is expected that GHG emissions restrictions will be applied to operations emitting more than 25,000 tonnes of CO_2 equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010 new reporting regulations (the "**Cap and Trade Regulations**") came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

Penn West's linear facility in British Columbia is covered by the Cap and Trade Regulations. We anticipate that we will have one facility over the 25,000 tonne threshold, two facilities between the 10,000 and 25,000 tonnes threshold, and twelve facilities between the 1,000 and 10,000 tonnes threshold. In addition, we have working interests in several non-operated facilities that are subject to the Cap and Trade Regulations. As at the date hereof, we do not believe that our financial obligations associated with the reporting and verification requirements under the Cap and Trade Regulations are material.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

Manitoba

The Government of Manitoba has indicated its intention to commence public consultations with respect to the development of a cap and trade system to reduce GHG emissions. No legislation with respect to an emissions reduction regime is currently in effect in Manitoba.

Penn West and the Environment

Penn West understands its responsibilities of reducing the environmental impacts from its operations and recognizes the interests of other land users in resource development areas, and conducts its operations accordingly. Penn West is committed to reducing the environmental impact from its operations, and to involving stakeholders throughout the exploration, development, production and abandonment process. Penn West's environmental programs encompass resource conservation, stakeholder communication and site abandonment/reclamation. Its environmental programs are monitored to ensure they comply with all government environmental regulations and with Penn West's own environmental policies. The results of these programs are reviewed with Penn West's management and operations personnel.

Penn West maintains 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 its field facilities. Penn West pursues a program of environmental impact reduction aimed at minimizing these future corporate liabilities without hampering field productivity. This program, launched in 1994 and ongoing into 2011, includes measures to remediate potential contaminant sources, reclaim spill sites and abandon unproductive wells and shut-in facilities. Penn West has implemented strategies to reduce greenhouse gas emissions and flaring and continued the program to test CO_2 enhanced oil recovery methods, which would "sequester" CO_2 in hydrocarbon reservoirs.

Alberta and British Columbia are currently the only jurisdictions in which Penn West operates that have passed legislation regarding greenhouse gas emissions, although several are contemplating new legislation. Penn West does not operate any facilities in Alberta that are regulated to reduce greenhouse gas emissions, however, it has one facility that is required to report its emissions. Penn West has minor working interests in five non-operated facilities that are required to meet the Alberta GHG regulations. All of Penn West's fuel use in British Columbia is subject to a carbon tax based on consumption. Penn West will be required to report its emissions in British Columbia and expects to have reduction requirements under a cap and trade system when implemented. Penn West's financial obligation, in both Alberta and British Columbia, to comply with legislation regarding greenhouse gas emissions is not material at this time.

Because the federal and provincial programs relating to the regulation of the emission of greenhouse gases and other air pollutants continue to be developed, Penn West is currently unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that Penn West could face increases in operating costs in order to comply with emissions legislation. However, in cooperation with CAPP, Penn West continues to work cooperatively with governments 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 oil and gas sector. In the meantime, Penn West will continue its current activities to reduce its emissions intensity, improve energy efficiency, and develop CO_2 injection and sequestration technology and infrastructure.

Penn West provides additional information on greenhouse gases on its website and also participates in the annual international Carbon Disclosure Project. These two sources detail significantly more information regarding emissions, business strategy, governance, and potential risks for those who are interested.

During 2010, Penn West completed CO_2 injection pilot testing in the Pembina and Swan Hills areas of Alberta. Both pilot projects provided valuable information which could lead to much larger enhanced oil recovery projects with the potential to sequester significant volumes of CO_2. Penn West also continued discussions with various parties regarding the supply and delivery of commercial amounts of CO_2 to its fields.

Penn West is committed to meeting its responsibilities to protect the environment wherever it operates and Penn West anticipates 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. Penn West will be taking such steps as required to ensure continued compliance with applicable environmental legislation in each jurisdiction in which it operates. Penn West believes that it is currently in compliance with applicable environmental laws and regulations in all material respects. Penn West also believes that it is reasonably likely that the trend towards heightened 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. 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. Shareholders and potential Shareholders should consider carefully the information contained herein and, in particular, the following risk factors. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in dividends paid on, and the market price of, our Common Shares.

Volatility in oil and natural gas prices could have a material adverse effect on our results of operations and financial condition, which in turn could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

Our results of operations and financial condition are dependent upon the prices that we receive for the oil and natural gas that we sell. Historically, the oil and natural gas markets have been volatile and are likely to continue to be volatile in the future. Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to:

- global energy policy, including the ability of OPEC to set and maintain production levels and influence prices for oil;
- existing and threatened political instability and hostilities;
- foreign supply of oil and natural gas, including liquefied natural gas;
- weather conditions;
- the overall level of energy demand;
- production and storage levels of natural gas;
- government regulations and taxes;
- currency exchange rates;
- the availability of transportation infrastructure;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies;
- the overall economic environment; and
- the advent of new technologies.

Any decline in the price of oil or natural gas could have a material adverse effect on our operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of reserves. Fluctuations in the price of oil and natural gas will also have an effect on the acquisition costs of any future oil and natural gas properties that we may acquire. In addition, cash dividends paid to our Shareholders are highly sensitive to the prevailing price of crude oil and natural gas and may decline with any decline in the price of oil or natural gas.

The price of oil and natural gas is affected by political events throughout the world. Any such event could result in a material decline in prices and in turn result in a reduction in the market price of our Common Shares and the amount of cash dividends paid to Shareholders.

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 and natural gas. Conflicts, or conversely peaceful developments, arising in North Africa, 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 our revenue and consequently the market price of our Common Shares and the amount of cash dividends paid to Shareholders.

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.

Seasonal factors and unexpected weather patterns may lead to declines in our activities and thereby adversely affect our business, the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

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.

We may be unable to successfully compete with other companies in our industry, which could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

There is strong competition relating to all aspects of the oil and gas industry. We compete with numerous other conventional exploration and production companies for, among other things:

- resources, including capital and skilled personnel;
- the acquisition of properties with longer life reserves and exploitation and development opportunities; and
- access to equipment, markets, transportation capacity, drilling and service rigs and processing facilities.

As a result of such increasing competition, it has become (and we expect it to continue to be) more difficult to acquire producing assets and reserves on accretive terms. We also compete for skilled industry personnel with a substantial number of other oil and gas companies.

Our hedging program could result in us not realizing the full benefit of oil and natural gas price increases.

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 potential credit risks associated with counterparties with which we contract.

If we are unable to acquire or develop additional reserves, the value of our Common Shares and the amount of cash dividends paid to Shareholders will decline.

Absent equity capital injections, increased debt levels or the efficient deployment of capital investments by us, our production levels and reserves will decline over time and, absent changes to other factors such as increases in commodity prices or improvements to our capital efficiency, the amount of cash dividends paid to our Shareholders will also decline over time.

Our future oil and natural gas reserves and production, and therefore our cash flow, will be highly dependent on our success in exploring and exploiting our reserves 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 depleted.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. To the extent that we are required to use higher proportions of our cash flow to finance capital expenditures or property acquisitions, the amount of cash dividends paid to our Shareholders could 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.

Fluctuations in foreign currency exchange rates and interest rates could adversely affect our business, and adversely affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

World oil prices are denominated in United States dollars and the Canadian dollar price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which fluctuates 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. Any such material increases in the value of the Canadian dollar negatively affect, among other things, our oil production revenues in Canadian dollars. We generally fund our cash costs, including our cash dividends, in Canadian dollars. Strengthening of the Canadian dollar against the United States dollar negatively affects the amount of Canadian dollar funds available to us for reinvestment and for the payment of future cash dividends, and negatively affects the future value of our reserves as calculated by independent evaluators.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a decrease in the amount of cash dividends paid to Shareholders, which would negatively impact the market price of the Common Shares.

Actual reserves will vary from reserves estimates and those variations could be material and negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquid reserves and resources and cash flow to be derived therefrom, including many factors beyond our control. The reserve and associated revenue information set forth herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- estimated production decline rates;
- ultimate estimated reserve recovery;
- changes in technology;
- timing and amount and effectiveness of future capital expenditures;
- marketability and price 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. As a result, 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 herein. Actual future net revenue 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 revenue derived from reserves will vary from the reserve estimates contained in the engineering reports summarized herein, and such variations could be material. The engineering reports summarized herein 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 revenue to be derived therefrom contained in the engineering reports summarized herein 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 herein.

Our operation of oil and natural gas wells, and our participation in oil and natural gas wells operated by others, could subject us to environmental claims and liability and/or increased compliance costs, all of which could affect the market price of our Common Shares and reduce the amount of cash dividends paid to Shareholders.

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 of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and 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 us to incur costs to remedy such discharge. Furthermore, the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions. Any such programs, laws or regulations, if proposed and enacted, may contain emission reduction targets that 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, the Copenhagen Accord, the federal government's Action Plan to Reduce Greenhouse Gases and Air Pollution announced on April 26, 2007 (the "**Action Plan**") and the federal government's update to the Action Plan announced on March 10, 2008 (the "**Updated Action Plan**"). The Action Plan includes the regulatory framework for air emissions. The Updated Action Plan provides additional guidance with respect to the federal government 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 the oil sands, oil and gas and refining industries. If passed, the Action Plan and the Updated Action Plan 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 and associated regulations, may require the reduction of emissions or emissions intensity of our operations and facilities. Further, federal proposals contained in the Updated Action Plan are now expected to be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation, which may differ significantly from the provisions contained in the Updated Action Plan. The direct or indirect costs of these regulations may adversely and materially affect our business. 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 of 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" herein.

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.

Under Canadian GAAP, the fair value of legal obligations for property abandonment and site restoration is recognized as a liability, discounted based on a credit-adjusted risk-free rate. Effective January 1, 2011, Canadian GAAP was replaced by IFRS and Penn West adopted these new accounting standards as of such date. Under IFRS, the fair value of legal and constructive obligations for property abandonment and site restoration is recognized as a liability. There is currently a diversity of practice when selecting the appropriate discount rate. A reduction in the discount rate used in the calculation could lead to a material increase in the asset retirement obligations recorded in Penn West's financial statements prepared in accordance with IFRS as compared to the asset retirement obligation recorded in Penn West's historical financial statements.

We depend upon our management and other key personnel and the loss of one or more of such individuals could negatively affect our business.

Shareholders depend upon the management of Penn West in respect of the administration and management of all matters relating to our operations. The success of our operations depends largely upon the skills and expertise of our senior management and other key personnel. Our continued success depends upon our ability to retain and recruit such personnel. Investors who are not willing to rely on the management of Penn West should not invest in our securities.

Cash dividends paid on our Common Shares are variable and may be reduced or suspended entirely.

The actual cash flow available for the payment of cash dividends to Shareholders can vary significantly from period to period for a number of reasons, including among other things: (i) our operational and financial performance (including fluctuations in the quantity of our oil, NGLs and natural gas production and the sales price that we realize for such production (after hedging contract receipts and payments)); (ii) fluctuations in the costs to produce oil, NGLs and natural gas, including royalty burdens, and to administer and manage Penn West; (iii) the amount of cash required or retained for debt service or repayment; (iv) amounts required to fund capital expenditures and working capital requirements; and (v) foreign currency exchange rates and interest rates. Certain of these amounts are, in part, subject to the discretion of the Board of Directors, which regularly evaluates Penn West's dividend payout with respect to anticipated cash flows, debt levels, capital expenditures plans and amounts to be retained to fund acquisitions and expenditures. In addition, our level of dividend per Common Share will be affected by the number of outstanding Common Shares.

Dividends on our Common Shares are neither preferential, cumulative nor stipulated by their terms to be at a fixed amount or rate. Dividends are declared by our Board in its sole discretion and are subject to change in accordance with our dividend policy. Our dividend policy is also subject to change in the Board's sole discretion. As a result, cash dividends may be increased, reduced or suspended entirely depending on our operations and the performance of our assets. The market value of the Common Shares may deteriorate if we are unable to meet dividend expectations in the future, and that deterioration may be material. See "Dividends and Dividend Policy".

We may not be able to achieve the anticipated benefits of acquisitions and the integration of acquisitions may result in the loss of key employees and the disruption of on-going business relationships.

We make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as 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, and may also result in the loss of key employees, the disruption of on-going business, supplier, customer and employee relationships and deficiencies in internal controls or information technology controls. We continually assess 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.

The incorrect assessment of value at the time of acquisitions could adversely affect the value of our Common Shares and the amount of cash dividends paid to our Shareholders.

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. If actual reserves or production are less than we expect, our revenues and consequently the value of our Common Shares and the amount of cash dividends paid to Shareholders could be negatively affected.

Our inability to manage growth could adversely affect our business and our Shareholders.

We may be subject to growth related risks, including capacity constraints and pressures on our internal systems and controls. These constraints and pressures could result from, among other things, the completion of large acquisitions. 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 Canadian income tax legislation and other laws may adversely affect us and our Shareholders.

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

Our indebtedness may limit the amount of cash dividends that we are able to pay to our Shareholders, and if we default on our debt, the net proceeds of any foreclosure sale would be allocated to the repayment of our lenders and other creditors and only the remainder, if any, would be available for distribution to our Shareholders.

Amounts paid in respect of interest and principal on debt we have incurred will reduce funds available for the payment of dividends. Variations in interest rates and any scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Certain covenants in the agreements with our lenders may also limit the amount of cash dividends paid in certain circumstances. Increases in interest rates could also result in decreases to the market value of our Common Shares. 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.

Changes in the regulation of the oil and gas industry may adversely affect our business.

Oil and natural gas operations (including exploration, production, pricing, marketing and transportation operations) are subject to extensive controls and regulations imposed by various levels of government that may be changed or amended from time to time. We have no control over these changes and amendments and the impact that they may have on us, and any such impact could be material and adverse. See "Industry Conditions".

Our operations 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.

Acquiring, exploring for and developing oil and natural gas assets involves many risks. Losses resulting from the occurrence of one or more of these risks may adversely affect our business and thus the value of our Common Shares and the amount of cash dividends paid to our Shareholders.

Acquiring, exploring for and developing oil and natural gas assets involves many risks. These risks include, but are not limited to:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- blowouts, equipment failures and other accidents;
- sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids;
- adverse weather conditions; and
- pollution and other environmental risks, such as 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 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.

We are participating in some large projects and have more concentrated risks in these areas of our operations.

We manage a variety of small and large projects in the conduct of our business. We have undertaken several large development projects, including PROP and the Cordova JV. Project delays may impact expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

The failure of third parties to meet their contractual obligations to us may have a material adverse affect on our financial condition.

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production and other parties. Poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Our exploration and development activities may be delayed if drilling and related equipment is unavailable or if access to drilling locations is restricted. These events could have an adverse impact on our business.

Oil and natural gas exploration and development activities depend 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 depend on such operators for the timing of activities related to such properties and are largely unable to direct or control the activities of the operators.

We do not operate all of our properties and facilities. Therefore, our results of operations may be adversely affected by pipeline interruptions and apportionments and the actions or inactions of third party operators, any of which could cause delays and additional expenses in receiving our revenues, which could in turn adversely affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

Continuing production from a property, and to some extent the marketing of production therefrom, largely depend upon the ability of the operator of the property or related facilities and the uninterrupted access to pipelines. Operating costs on most properties have increased over recent years. To the extent the operator fails to perform these functions properly or pipeline access is restricted, revenues will 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.

An unforeseen defect in the chain of title to our oil and natural gas producing properties may arise to defeat our claim, which could have an adverse affect on the market price of our Common Shares and could reduce the amount of cash dividends paid to our Shareholders.

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 in the amount of revenue received by us and consequently the funds available for the payment of cash dividends to Shareholders.

The termination or expiration of licenses and leases through which we or our industry partners hold our interests in petroleum and natural gas substances could adversely affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

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 all 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 effect on our results of operations and business.

We are exposed to potential liabilities that may not be covered, in part or in whole, by insurance.

Our involvement in the exploration 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, we 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, we 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 the amount of funds otherwise available to us for the payment of cash dividends.

Dividends might be reduced during periods in which we make capital expenditures using our cash flow from operations, which could negatively affect the market price of our Common Shares.

Future oil and natural gas reserves and hence revenues are highly dependent on our success in exploiting existing properties and acquiring additional reserves. We also intend to dividend a portion of our net cash flow to Shareholders rather than reinvesting it in reserve additions and production growth or maintenance. Accordingly, if external sources of capital, including the issuance of additional Common Shares, become limited or unavailable on commercially reasonable terms, 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 our cash flow from operations to finance capital expenditures or property acquisitions, the amount of cash available for the payment of dividends to Shareholders 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 decline 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 our Common Shares and in a reduction in the amount of cash available for the payment of dividends to Shareholders.

Delays in business operations could adversely affect the payment of cash dividends to Shareholders and the market price of the Common Shares.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of oil and natural gas properties, and by the operator to us, 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. Any one or more of these delays could adversely affect our ability to pay cash dividends to Shareholders and thus adversely affect the market price of our Common Shares.

We may in the future expand our operations into new geographical regions where our existing management does not have experience. In addition, we may in the future acquire new types of energy related assets in respect of which our existing management does not have experience. Any such expansion or acquisition could result in our exposure to new risks that if not properly managed could ultimately have an adverse effect on our business, the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

The operations and expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canadian Sedimentary Basin. In the future, we may acquire or develop oil and gas properties outside of this geographic area. In addition, we could acquire other energy related assets, such as upgraders or pipelines. Expansion of our activities into new areas may present new risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Non-Residents of Canada may be subject to additional taxation by Canadian or foreign governments that may adversely affect them.

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the cash dividends or other property paid or distributed by us to Shareholders who are Non-Residents of Canada, and these taxes may change from time to time.

Additionally, the reduced "Qualified Dividend" rate of 15 percent tax which has applied to our distributions under current U.S. tax laws is scheduled to expire at the end of 2012 and there is no assurance that this reduced tax rate will be renewed by the U.S. government at such time.

We use conventional recovery methods, such as horizontal multi-stage fracture technology, and non-conventional recovery methods, such as enhanced oil recovery technologies, both of which are subject to significant risk factors which could lead to the delay or cancellation of some or all of our projects, which could adversely affect the market price of our Common Shares and our dividends to Shareholders.

Penn West utilizes new drilling and completion technologies, including horizontal multi-fracture completions, intended to increase the resource recovery from known producing oil and natural gas fields. However, Penn West may not realize the anticipated increase in resource recovery from the employment of such techniques due to particular reservoir characteristics or other adverse factors.

The potential or planned use of enhanced oil recovery (" **EOR**") methods such as steam injection (steam assisted gravity drainage, cyclical steam stimulation and steam flooding), solvent injection and firefloods to increase the ultimate recovery of oil resources in place are subject to significant risk factors. These factors include but are not limited to the following:

- changing economic conditions (including commodity pricing and operating and capital expenditure fluctuations);
- changing engineering and technical conditions (including the ability to apply EOR methods to the reservoir and the production response thereto);
- large development programs may need to be spread over a longer time period than initially planned due to the requirement to allocate capital expenditures to different periods;
- surface access and deliverability issues (including landowner and stakeholder relations, weather, pipeline, road and processing matters);
- environmental regulations relating to such items as greenhouse gas emissions and access to water, which could impact capital and operating costs; and
- the availability of sufficient financing on acceptable terms.

The use or potential or planned use of carbon dioxide miscible flooding to increase the oil recovery from large legacy oil pools 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:

- the existence of commercial scale CO_2 supply and infrastructure (including the ability to capture and transport the miscible agent to us at an economic cost);
- changing economic conditions (including commodity pricing and operating and capital expenditure fluctuations);
- changing engineering and technical conditions (including the ability to apply CO_2 EOR methods to the reservoir and the production response thereto);
- large development programs may need to be spread over a longer time period than planned due to capital allocation requirements;
- the need to obtain required approvals from regulatory authorities from time to time;
- surface access and deliverability issues (including weather, pipeline, road and processing matters);
- the availability of sufficient financing on acceptable terms;
- changing regulatory frameworks, which could impact our long term storage liability and our monitoring, measurement and verification costs on CO_2 miscible flood projects;
- changing royalty structures which may impact CO_2 flood economics; and
- the potential for out-of-zone and wellbore leakage which could delay or cause the cancellation of some or all of these projects.

Dilution to Shareholders.

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities, which may be dilutive to Shareholders. In addition, we may determine to redeem the currently outstanding Convertible Debentures for Common Shares or to settle the interest and/or pay the redemption price at maturity of such Convertible Debentures by issuing additional Common Shares. Shareholders may suffer dilution in the event of any such issuance of Common Shares.

Shareholder dilution may also result from the issuance of Common Shares pursuant to our stock option plan (" **Option Plan**"), our Common Share Rights Incentive Plan ("**CSRIP"**) and our Dividend Reinvestment and Optional Common Share Purchase Plan (" **DRIP**"). For more information regarding our Option Plan, our CSRIP and our DRIP, see our most recent Information Circular and Proxy Statement, financial statements and related management's discussion and analysis filed on SEDAR at www.sedar.com.

There might not always be an active trading market in the United States and/or Canada for the Common Shares and/or the Convertible Debentures.

While there is currently an active trading market for the Common Shares in both the United States and Canada, we cannot guarantee that an active trading market will be sustained in either country. If an active trading market in the Common Shares is not sustained, the trading liquidity of the Common Shares will be limited and the market value of the Common Shares may be reduced.

There has not been an active trading market for the Convertible Debentures in Canada, and we cannot guarantee that an active trading market will develop. If an active trading market for the Convertible Debentures does not develop, the trading liquidity of the Convertible Debentures will remain limited and the market value of the Convertible Debentures may be adversely affected.

The impact on us of claims of aboriginal title is unknown.

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

Our directors and management may have conflicts of interest that may create incentives for them to act contrary to or in competition with the interests of our Shareholders.

Certain directors and officers of Penn West 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 Penn West 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 must disclose his interest in such contract or agreement and must 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 and our Code of Business Conduct and Ethics.

Our Common Shares may from time to time trade at a price that is less than our net asset value per Common Share.

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

The ability of residents of the United States to enforce civil remedies against us and our directors, officers and experts may be limited.

Penn West is organized under the laws of Alberta, Canada and our principal places of business are in Canada. Most of our directors and all of our officers and the experts named herein are residents of Canada, and a substantial portion of our assets 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 those directors, officers and experts who are not residents of the United States or to enforce against them judgments of 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 us or against any of our directors, officers or experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in 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.

The primary differences between the United States requirements and the NI 51-101 requirements are that the SEC generally: (i) permits reporting oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves and production, net of royalties and interests of others; and (ii) does not permit the disclosure of resources. The SEC generally does not permit reporting companies to disclose net present value of future net revenue from reserves based on forecast prices and costs. NI 51-101 permits, among other things, disclosure of production on a gross basis before deducting royalties.

Our cash dividends are declared in Canadian dollars and Non-Resident investors are therefore subject to foreign exchange risk that could adversely affect the amount of cash dividends received by them.

Our cash dividends are declared in Canadian dollars and converted to foreign denominated currencies at the 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 cash dividend will be reduced when converted to their home currency.

If oil and gas prices decline, we may be required under applicable accounting standards to write down the value of our assets.

Historically, Canadian GAAP required 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 were carried as net assets on the balance sheet were subject to a cost-recovery or "ceiling" test, which was based in part upon estimated future net revenues from reserves. If net capitalized costs exceeded the estimated recoverable amounts, we would have to charge the amount of the excess to net income. A decline in the net value of oil and natural gas properties could have caused capitalized costs to exceed the cost ceiling, resulting in a non-cash charge against income. The value of oil and gas properties is highly dependent upon the prices of oil and natural gas.

Under U.S. GAAP, the estimated recoverable amounts are calculated based on estimated future net revenues from proved reserves discounted at ten percent and using the average of commodity prices on the first day of each month of the preceding year. The use of discounting and constant prices has historically resulted in a greater likelihood of a write-down under U.S. GAAP than Canadian GAAP.

Effective January 1, 2011, Penn West will follow the accounting guidelines under IFRS. Under IFRS, the ceiling test or impairment test will be performed at a lower level than under Canadian GAAP. As a consequence, impairment provisions are more likely to occur going forward under IFRS, as properties will no longer be tested at only the country level and impairment can also be reversed if parameters change in the future.

For further information regarding our expectations as to the effect that the initial adoption of IFRS will have on our financial statements and financial performance, see "**Future Accounting Pronouncements – Implementation of International Financial Reporting Standards**" and "**IFRS impacts related to our corporate conversion**" in our management's discussion and analysis for the year ended December 31, 2010 filed on SEDAR at www.sedar.com, which disclosure is incorporated by reference into this Annual Information Form.

In certain circumstances we may be required under applicable accounting standards to write down the value of the goodwill recorded on our balance sheet and incur a non-cash charge against net income.

Canadian GAAP required that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the Common Share price could indicate goodwill impairment. As at December 31, 2010, we had approximately $2 billion recorded on our balance sheet as goodwill arising from historical acquisitions. An impairment would result in a write-down of the goodwill value and a non-cash charge against income. The calculation of impairment value is subject to management estimates and assumptions.

The guidance under IFRS is similar to Canadian GAAP, therefore, impairment charges could be recorded going forward. In some circumstances, the assessment under IFRS is at a lower level than it was under Canadian GAAP, and therefore, goodwill impairments are more likely to occur going forward under IFRS.

A decrease in the fair market value of our hedging instruments could result in a non-cash charge against our income under applicable accounting standards.

Both Canadian GAAP and IFRS 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 a result of fluctuations in commodity prices and/or foreign exchange rates may result in a non-cash charge against income.

We cannot assure you that the dividends and distributions you receive over the life of your investment will meet or exceed your initial capital investment, which is at risk.

Common Shares will have no value when the underlying petroleum and natural gas properties can no longer be economically produced and, as a result, cash dividends 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. Dividends can represent a *return of* or a *return on* Shareholders' capital.

We may not be able to repay all or part of our indebtedness, or alternatively refinance all or part of our indebtedness on commercially reasonable terms. We may not be able to comply with the covenants (and in particular the financial covenants) contained in our debt instruments. The occurrence of any one of these events could have a material adverse effect on our results of operations and financial condition, which in turn could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

We currently have a credit facility in place that has an aggregate borrowing limit of $2.25 billion and a maturity date of April 30, 2013, which is extendible with lender approval. As of March 17, 2011, approximately $0.9 billion was outstanding under our credit facility. In the event that our credit facility is not extended before April 30, 2013, all outstanding indebtedness thereunder will be repayable at that date. There is also a risk that our credit facility will not be renewed for the same principal amount or on the same terms. Any of these events could adversely affect our ability to fund our ongoing operations and, as repayment of such indebtedness has priority over the payment of dividends to Shareholders, to pay cash dividends to Shareholders.

We also currently have: (i) US$1,529 million principal amount of Senior Notes, Cdn$145 million principal amount of Senior Notes, £77 million principal amount of Senior Notes and €10 million principal amount of Senior Notes outstanding, which require principal repayments starting in May 2014 and continuing until December 2025; and (ii) $255 million principal amount of Convertible Debentures outstanding which require principal repayments starting in May 2011 and continuing until December 2011. In the event we are unable to repay or refinance these debt obligations it may adversely affect our ability to fund our ongoing operations and, as repayment of such indebtedness has priority over the payment of dividends to Shareholders, to pay cash dividends to Shareholders.

We are required to comply with covenants under our credit facilities and Senior Notes. In the event that we do not comply with covenants under one or more of these debt instruments, our access to capital could be restricted or repayment could be required, which could adversely affect our ability to fund our ongoing operations and, as repayment of such indebtedness has priority over the payment of dividends to Shareholders, to pay cash dividends to Shareholders.

We will require additional financing from time to time, which may result in dilution to Shareholders. If we are unable to obtain additional financing at all or on reasonable terms, the amount of cash dividends paid to Shareholders could be reduced.

In the normal course of making capital investments to maintain and expand our oil and gas reserves, additional Common Shares may be issued which may result in a decline in, including but not limited to, production per Common Share and reserves per Common Share. Additionally, from time to time, we may issue Common Shares 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 Common Shares, becomes limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and gas reserves will be impaired. To the extent that we are required to use additional cash flow to finance capital expenditures or property acquisitions, or to pay debt service charges or reduce debt, the amount of cash dividends paid to Shareholders could be reduced.

The global financial crisis and severe recession experienced in 2008 and 2009 had an adverse effect on commodity prices and on our access to capital. Should one or both of these conditions be experienced again in the future, they could have a material adverse effect on our results of operations and financial condition, which in turn could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

The global financial crisis and severe recession experienced in 2008 and 2009, which included disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, caused significant volatility to commodity prices and a loss of confidence in the broader U.S. and global credit and financial markets, resulting in the collapse of some, and government intervention in many, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, increased credit losses and tighter credit conditions. Notwithstanding various actions taken by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially (although credit markets and stock markets have since improved significantly). These factors negatively impacted company valuations (which have since improved significantly) but are expected to continue to impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, geo-political events, OPEC actions and the ongoing global credit and liquidity concerns.

As a result of the weakened global economic situation, we (and all other oil and gas entities) may experience restricted access to capital and increased borrowing costs in the future. Although our business and asset base have not changed materially, the lending capacity of certain financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to make capital expenditures will be dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition, results of operations and dividends may be materially and adversely affected as a result.

At March 17, 2011, we had approximately $1.4 billion of unused credit available under our credit facilities. Based on current funds available and expected cash from operations, we believe that we have sufficient funds available to fund our projected capital expenditures. However, if cash flow from operations is lower than expected or capital costs for our projects exceeds current estimates, or if we incur major unanticipated expenses related to the development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain financing necessary for our capital expenditure plans may result in a delay in development or production on our properties and/or a decrease of the amount of cash dividends that we pay to Shareholders.

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 by us or one of our Subsidiaries within the most recently completed financial year or before the most recently completed financial year but which are still material and are still in effect, are the following:

(a) the Debenture Indentures described under "Capitalization of Penn West – Debt Capital – Convertible Debentures";

(b) the credit agreement dated April 30, 2010 (as amended by first amending agreement dated as of July 12, 2010 and by second amending agreement dated as of November 17, 2010) among Penn West and certain lenders and other parties in respect of Penn West's $2.25 billion syndicated credit facility, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes and Credit Facility";

(c) the note purchase agreement dated May 31, 2007 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of the 2007 Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes and Credit Facility";

(d) the note purchase agreement dated May 29, 2008 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of the 2008 Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes and Credit Facility";

(e) the note purchase agreement dated July 31, 2008 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of the 2008 Senior Notes (Pounds Sterling), which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes and Credit Facility";

(f) the note purchase agreement dated May 5, 2009 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of the 2009 Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes and Credit Facility";

(g) the note purchase agreement dated March 16, 2010 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of the 2010 Q1 Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes and Credit Facility"; and

(h) the note purchase agreement dated December 2, 2010 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of the 2010 Q4 Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes and Credit Facility".

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

Changes to Contracts

There is currently no aspect of our business that we reasonably expect to be materially affected in the current financial year by the renegotiation or termination of contracts or sub-contracts. All of our Convertible Debentures mature in the ordinary course of business during 2011.

Economic Dependence

We are not currently a party to any contract on which our business is substantially dependent, including any contract to sell the major part of our products or to purchase the major part of our requirements for goods, services or raw materials, or any franchise or licence or other agreement to use a patent, formula, trade secret, process or trade name on which our business depends.

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 knows to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by us if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10 percent of our current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, we have included the amount involved in the other proceedings in computing the percentage.

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 our 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 Common Shares in Canada is CIBC Mellon Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario. The co-transfer agent and registrar for the Common Shares in the United States is BNY Mellon Shareowner Services at its principal offices in Jersey City, New Jersey.

The transfer agent and registrar for the 7.2% Debentures is Valiant Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario. The transfer agent and registrar for the 6.5% 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 Penn West, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of the outstanding Common Shares, or any known associate or affiliate of any such person, in any transaction within Penn West's three most recently completed financial years or during our current financial year that has materially affected or is reasonably expected to materially affect Penn West.

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, other than GLJ and Sproule, our independent engineering evaluators (GLJ and Sproule each an "**Engineer**" and collectively, the " **Engineers**"), KPMG LLP ("**KPMG**"), our auditors, and Burnet, Duckworth & Palmer LLP, our legal counsel ("**BDP**", and together with the Engineers, the " **Experts**").

There were no registered or beneficial interests, direct or indirect, in any securities or other property of Penn West or of one of our associates or affiliates: (i) held by an Expert and by the "designated professionals" (as defined in Form 51-102F2 – *Annual Information Form*) of the Expert, when that Expert prepared the relevant report, valuation, statement or opinion; (ii) received by an Expert and by the "designated professionals" of that Expert, after the preparation of the relevant report, valuation, statement or opinion; or (iii) to be received by an Expert and by the "designated professionals" of that Expert; except with respect to the ownership of our Common Shares and / or Convertible Debentures, in which case the person's or company's interest in our Common Shares and / or Convertible Debentures represents less than one percent of our outstanding Common Shares and / or Convertible Debentures, respectively.

KPMG are the auditors of Penn West and have confirmed that they are independent with respect to Penn West within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and within the meaning of the U.S. Securities Act of 1933 and the applicable rules and regulations thereunder adopted by the SEC and the Public Company Accounting Oversight Board (United States).

No director, officer or employee of GLJ, Sproule, KPMG or BDP is or is expected to be elected, appointed or employed as a director, officer or employee of Penn West or of any associate or affiliate of Penn West, except for John A. Brussa, the Chairman of Penn West, who is a partner of BDP.

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 securityholders that involved the election of directors. 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. ("**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, 2010, estimated using forecast prices and costs.

Independent qualified reserves evaluators (or in some cases qualified reserves auditors) have evaluated (or in some cases audited) Penn West's reserves data. The report of the independent qualified reserves evaluators (or in some cases qualified reserves auditors) is presented below.

The Reserves Committee of the Board of Directors of Penn West has:

(a) reviewed Penn West's procedures for providing information to the independent qualified reserves evaluators (or in some cases qualified reserves auditors);

(b) met with the independent qualified reserves evaluators (or in some cases qualified reserves auditors) to determine whether any restrictions affected the ability of the independent qualified reserves evaluators (or in some cases qualified reserves auditors) to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators (or in some cases qualified reserves auditors).

The Reserves Committee of the Board of Directors of Penn West 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 evaluators (or in some cases qualified reserves auditors) 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.

(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) Jack Schanck
Director and Member of the Reserves Committee

March 17, 2011

APPENDIX A-2

REPORT ON RESERVES DATA

(Form 51-101F2)

To the Board of Directors of Penn West Petroleum Ltd. (" **Penn West**"):

1. We have evaluated (or in some cases audited) Penn West's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Penn West's management. Our responsibility is to express an opinion on the reserves data based on our evaluation (or in some cases our audit).

   We carried out our evaluation (or in some cases our audit) 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 (or in some cases an audit) to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation or audit also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Penn West evaluated and audited by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have evaluated and audited and reported on to Penn West's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation / Audit 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.	January 28, 2011	Canada	$ -	$ 5,315	$ -	$ 5,315
Sproule Associates Limited	February 11, 2011	Canada	$ 1,067	$ 4,353	$ -	$ 5,420
Sproule Associates Limited	February 11, 2011	USA	$ -	$ 36	$ -	$ 36
Total			$ 1,067	$ 9,704	$ -	$ 10,771

5. In our opinion, the reserves data respectively evaluated or audited by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. 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.

Executed as to our report referred to above:

(signed) GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada
March 17, 2011

(signed) Sproule Associates Limited
Calgary, Alberta, Canada
March 17, 2011

APPENDIX A-3

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Our statement of reserves data and other oil and gas information dated March 17, 2011 is set forth below (the " **Statement**"). The effective date of the Statement is December 31, 2010 and the preparation date of the Statement is March 17, 2011. The Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by GLJ and Sproule on Form 51-101F2 are attached as Appendices A-1 and A-2, respectively, to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon: (i) an evaluation prepared by GLJ with an effective date of December 31, 2010 contained in the GLJ Report dated January 28, 2011; and (ii) an evaluation and audit prepared by Sproule with an effective date of December 31, 2010 contained in the Sproule Report dated February 11, 2011. 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 evaluate approximately 47 percent of our proved and proved plus probable reserves. We engaged Sproule to evaluate approximately 43 percent and to audit approximately 10 percent of our proved and proved plus probable reserves. See also "Notes to Reserve Data Tables" below.

The vast majority of our proved plus probable reserves are located in Canada in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories. We also have minor proved plus probable reserves interests in the United States in Wyoming and North Dakota. The reserves information presented below does not report reserves that are located in the United States separately. Our properties located in the United States have proved plus probable gross reserves of approximately 3.0 MMboe, which represents less than one percent of our total proved plus probable reserves, and have a before tax net present value discounted at 10 percent of approximately $36 million, which represents less than one percent of the total value of our proved plus probable reserves.

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 price and cost 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".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2010
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (MMbbl)	Net (MMbbl)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	203	175	51	45
Developed Non-Producing	5	4	2	1
Undeveloped	51	44	1	1
TOTAL PROVED	259	223	54	47
PROBABLE	94	79	14	12
TOTAL PROVED PLUS PROBABLE	353	302	68	60

RESERVES CATEGORY	RESERVES NATURAL GAS Gross (Bcf)	RESERVES NATURAL GAS Net (Bcf)	RESERVES NATURAL GAS LIQUIDS Gross (MMbbl)	RESERVES NATURAL GAS LIQUIDS Net (MMbbl)
PROVED				
Developed Producing	735	646	21	15
Developed Non-Producing	47	39	1	1
Undeveloped	83	73	2	2
TOTAL PROVED	865	758	24	17
PROBABLE	370	320	9	7
TOTAL PROVED PLUS PROBABLE	1,235	1,078	33	24

RESERVES CATEGORY	RESERVES TOTAL OIL EQUIVALENT Gross (MMboe)	RESERVES TOTAL OIL EQUIVALENT Net (MMboe)
PROVED		
Developed Producing	398	343
Developed Non-Producing	16	13
Undeveloped	68	58
TOTAL PROVED	481	414
PROBABLE	180	151
TOTAL PROVED PLUS PROBABLE	661	565

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2010
BEFORE INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	Unit Value Before Income Tax Discounted at 10%/year[1] ($/bbl)	Unit Value Before Income Tax Discounted at 10%/year[1] ($/Mcf)
PROVED							
Developed Producing	12,873	9,126	7,202	6,017	5,206	21.00	3.50
Developed Non-Producing	448	333	261	214	182	20.08	3.35
Undeveloped	2,464	1,401	881	585	400	15.19	2.53
TOTAL PROVED	15,784	10,860	8,344	6,817	5,788	20.14	3.36
PROBABLE	7,266	3,848	2,426	1,693	1,260	16.07	2.68
TOTAL PROVED PLUS PROBABLE	23,051	14,708	10,771	8,510	7,048	19.05	3.18

Note:

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

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2010
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	11,220	8,170	6,572	5,570	4,875
Developed Non-Producing	336	252	200	166	143
Undeveloped	1,850	1,033	629	399	254
TOTAL PROVED	13,406	9,455	7,401	6,135	5,272
PROBABLE	5,436	2,874	1,804	1,252	927
TOTAL PROVED PLUS PROBABLE	18,842	12,329	9,205	7,387	6,198

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2010
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	38,254	5,572	14,459	1,389	1,050	15,784	2,379	13,406
Proved Plus Probable Reserves	53,786	8,103	19,366	2,085	1,181	23,051	4,208	18,842

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2010
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]	6,372	20.17	3.36
	Heavy Oil[1]	1,236	24.42	4.07
	Natural Gas[2]	683	17.21	2.87
	Non-Conventional Oil and Gas Activities	53	6.53	1.09
	TOTAL	8,344	20.14	3.36
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	8,323	19.20	3.20
	Heavy Oil[1]	1,509	23.60	3.93
	Natural Gas[2]	834	15.81	2.63
	Non-Conventional Oil and Gas Activities	104	6.89	1.15
	TOTAL	10,771	19.05	3.18

Notes:

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

(2) Including by-products but excluding solution gas and by-products from oil wells.

(3) Revenues and costs not related to a specific production group have been allocated proportionately to each production group. 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 Engineering Reports are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook (the "**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.

(d) **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.

(e) **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.

(f) **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.

(g) **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 reserves 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 quantitative 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, 2010, inflation and exchange rates utilized in the Engineering Reports were as set forth below. The price assumptions set forth below were provided by GLJ and Sproule.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

	OIL					EDMONTON LIQUIDS PRICES				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40ºAPI ($Cdn/bbl)	Lloydminster Blend 21ºAPI ($Cdn/bbl)	Cromer Medium 29ºAPI ($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 $1.00 Cdn)
Forecast										
2011	88.20	89.65	77.31	84.20	4.10	54.76	64.85	92.93	2%	0.96
2012	89.07	91.57	77.63	84.69	4.70	55.95	65.85	94.04	2%	0.96
2013	89.38	92.17	76.11	84.33	5.15	56.35	66.34	94.21	2%	0.96
2014	90.44	93.25	75.76	84.39	6.17	57.02	67.16	95.31	2%	0.96
2015	92.69	95.57	77.65	86.50	6.45	58.46	68.88	97.68	2%	0.96
2016	94.56	97.50	79.21	88.25	6.66	59.65	70.30	99.65	2%	0.96
2017	96.60	99.61	80.92	90.16	6.83	60.95	71.85	101.81	2%	0.96
2018	98.54	101.62	82.54	91.98	6.96	62.19	73.32	103.86	2%	0.96
2019	100.60	103.75	84.27	93.91	7.10	63.50	74.89	106.03	2%	0.96
Thereafter	2%	2%	2%	2%	2%	2%	2%	2%	2%	-

Notes:

(1) Inflation rates for forecasting prices and costs. Inflation assumptions used by GLJ and Sproule were 1.8 percent and 2.0 percent, respectively.

(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, 2010 were $4.62/Mcf for natural gas, $69.78/bbl for light and medium crude oil, $60.55/bbl for heavy oil and $47.58/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$)	Proved Plus Probable Reserves (MM$)
2011	662	928
2012	213	349
2013	117	188
2014	104	141
2015	60	93
2016 and subsequent	233	386
Total: Undiscounted for all years	1,389	2,085

We currently expect to fund the development costs of the reserves through internally generated cash flow.

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 Engineering Reports. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to our reserves.

The interest and other costs of 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 and Sproule in determining the aggregate future net revenue therefrom.

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

7. All factual data supplied to GLJ and 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.

Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2010, using forecast price and cost estimates derived from the Engineering Reports.

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

	LIGHT AND MEDIUM OIL[2]			HEAVY OIL[2]			NATURAL GAS[2]		
FACTORS	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (Bcf)	Gross Probable (Bcf)	Gross Proved Plus Probable (Bcf)
December 31, 2009	261	107	368	56	15	71	938	354	1,292
Extensions	15	5	20	-	-	-	46	49	95
Improved Recovery[1]	11	4	15	2	-	3	12	3	15
Technical Revisions	7	(3)	4	2	-	2	59	(30)	29
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	9	3	12	3	2	5	27	12	39
Dispositions	(18)	(22)	(40)	(3)	(2)	(4)	(48)	(9)	(58)
Economic Factors	(1)	-	(1)	(1)	(1)	(2)	(27)	(9)	(36)
Production	(25)	-	(25)	(7)	-	(7)	(141)	-	(141)
December 31, 2010	259	94	353	54	14	68	865	370	1,235

Note:

(1) Improved recovery includes the following infill drilling:

Infill Drilling	9	5	13	1	-	1	9	4	12

	NATURAL GAS LIQUIDS[2]			TOTAL OIL EQUIVALENT[2]		
FACTORS	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMboe)	Gross Probable (MMboe)	Gross Proved Plus Probable (MMboe)
December 31, 2009	24	9	33	497	190	687
Extensions	1	-	1	23	14	38
Improved Recovery[1]	-	-	1	16	5	20
Technical Revisions	3	-	3	22	(8)	14
Discoveries	-	-	-	-	-	-
Acquisitions	1	-	1	17	8	25
Dispositions	(1)	-	(1)	(29)	(26)	(55)
Economic Factors	-	-	-	(6)	(3)	(9)
Production	(4)	-	(4)	(59)	-	(59)
December 31, 2010	24	9	33	481	179	661

Notes:

(1) Improved recovery includes the following infill drilling:

Infill Drilling	-	-	-	12	5	17

(2) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ and 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 two-thirds of the proved undeveloped reserves in the Engineering Reports over the next two years and the significant majority of the proved undeveloped reserves over the next five years. Penn West plans to develop approximately one-half of the probable undeveloped reserves in the Engineering Reports over the next two years and the significant majority of the probable 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).

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 (MMbbl)		Heavy Oil (MMbbl)		Natural Gas (Bcf)		NGLs (MMbbl)	
	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	34	34	1	1	38	38	1	1
2008	9	37	5	6	44	62	-	1
2009	17	46	-	2	7	61	-	1
2010	16	51	-	1	28	83	1	2

GLJ and Sproule have assigned 68 MMboe of proved undeveloped reserves in the Engineering Reports under forecast prices and costs, together with $1,098 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Engineering Reports accounts for $796 million, or 72 percent, of the total forecast undiscounted capital expenditures for proved undeveloped reserves. These figures increase to $1,006 million, or 92 percent, during the first five years of the Engineering Reports. The majority of our proved undeveloped reserves evaluated in the Engineering Reports are attributable to future oil development from infill drilling and enhanced oil recovery projects.

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.

Year	Light and Medium Oil (MMbbl)		Heavy Oil (MMbbl)		Natural Gas (Bcf)		NGLs (MMbbl)	
	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	24	24	1	1	26	26	2	2
2008	11	32	13	13	57	79	1	2
2009	26	51	-	2	7	60	-	2
2010	11	36	1	1	52	112	-	2

GLJ and Sproule have assigned 59 MMboe of probable undeveloped reserves in the Engineering Reports under forecast prices and costs, together with $609 million of associated undiscounted future capital expenditures. Probable undeveloped capital spending in the first two forecast years of the Engineering Reports accounts for $370 million, or 61 percent, of the total forecast undiscounted future capital expenditures for probable undeveloped reserves. These figures increase to $486 million, or 80 percent, during the first five years of the Engineering Reports. The probable undeveloped reserves evaluated in the Engineering Reports 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 Affecting Reserves Data

The development schedule for our undeveloped reserves is based on forecast price assumptions for the determination of economic projects. The actual market prices for oil and natural gas may be significantly lower or higher resulting in some projects being delayed or accelerated, as the case may be. See "Risk Factors".

We do not anticipate that any significant economic factors or other significant uncertainties will affect any particular components of our reserves data. However, our 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

Abandonment and reclamation costs in respect of surface leases, wells, facilities and pipelines (collectively, " **A&R Costs**") are primarily comprised o well bore abandonment and reclamation costs, and liability issues such as flare pit remediation and facility decommissioning, remediation, and reclamation costs. A&R Costs are estimated using our experience conducting annual abandonment and reclamation programs over the past several years.

We review suspended or standing well bores for reactivation, recompletion or sale and conduct abandonment programs for those well bores that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned subsequent to the time when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs and continuous operations to reduce costs.

As of December 31, 2010, we expect to incur future A&R Costs in respect of approximately 22,912 net well bores and 2,630 facilities. The total amount of A&R Costs, net of estimated salvage values, that we expect to incur, including wells that extend beyond the 50-year limit in the Engineering Reports, 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, 2010	3,057	375
Anticipated to be paid in 2011	70	64
Anticipated to be paid in 2012	71	59
Anticipated to be paid in 2013	73	55

The above table includes certain A&R Costs, net of estimated salvage values, not included in the Engineering Reports and not deducted in estimating future net revenue as disclosed earlier in this Annual Information Form. Escalated at two percent and undiscounted, the A&R Costs not deducted were $1,422 million, and escalated at two percent and discounted at 10 percent, these A&R Costs were $175 million.

OTHER OIL AND GAS INFORMATION

Description of Our Properties, Operations and Activities in Our Major Operating Regions

Introduction

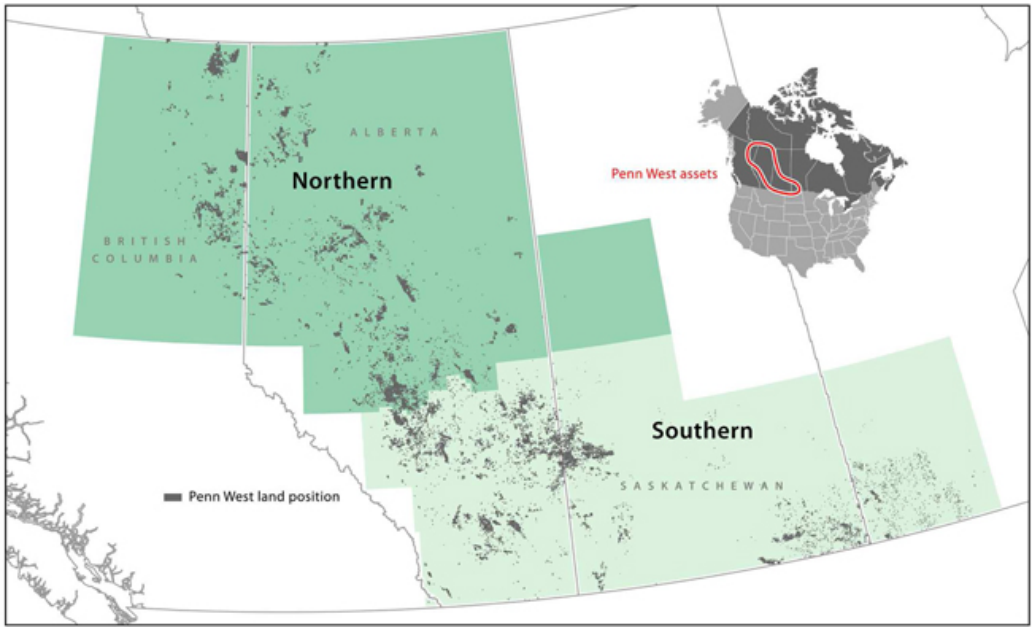
Penn West participates in the exploration for, and the development and production of, oil and natural gas principally in western Canada. Our portfolio of properties as at December 31, 2010 includes both unitized and non-unitized oil and natural gas production. In general, the properties contain long-life, low-decline rate reserves and include interests in several major oil and gas fields. The majority of our proved plus probable reserves are located in Canada in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories. We also have minor proved plus probable reserves interests in the United States in Wyoming and North Dakota.

Major Operating Regions

Our production and reserves are attributed to approximately 300 producing properties. No single property accounts for more than 10 percent of our proved plus probable reserves. Penn West's operations are managed based on two major operating regions, the Southern District and the Northern District. The following table shows our reported average daily production in 2010 and proved plus probable reserves, as at December 31, 2010, by major operating region. These two major operating regions represented all of our average daily production in 2010 and all of our total gross proved plus probable reserves (based on forecast cost and price assumptions) as assigned by GLJ and Sproule in the Engineering Reports.

	Average Daily Production in 2010			Proved Plus Probable Gross Reserves as at December 31, 2010			Land as at December 31, 2010 (thousands of acres)		
	Crude Oil and NGLs (bbl/d)	Natural Gas (MMcf/d)	Total Oil Equivalent (boe/d)	Crude Oil and NGLs (MMbbl)	Natural Gas (Bcf)	Total Oil Equivalent (MMboe)	Producing	Non-producing	Total
Southern	56,944	182	87,262	250	556	342	2,260	1,070	3,330
Northern	42,022	212	77,371	205	679	319	1,925	1,023	2,948
Total	98,966	394	164,633	455	1,235	661	4,185	2,093	6,278
	60% of daily production	40% of daily production		69% of total reserves	31% of total reserves				

The following map illustrates Penn West's two major operating regions as at December 31, 2010.



The following is a description of our principal oil and natural gas properties and related operations and activities by major operating district, including the key resource plays within each district, as at December 31, 2010. Information in respect of gross and net acres and well counts are as of December 31, 2010, and information in respect of production is for the year ended December 31, 2010, 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 in gross and net acres and wells at December 31, 2010 may not directly correspond to our reported production for the year, which only includes production from the date of acquisition. **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.**

Southern District

The Southern District includes properties within Manitoba, Saskatchewan, and Southern and East Central Alberta. This district also contains minor operations and land positions in the states of North Dakota, Wyoming and Montana. In 2010, production in this district averaged 87,262 boe per day, comprised of approximately 56,944 barrels per day of liquids and 182 MMcf per day of natural gas. The three main resource plays in the Southern District are Waskada, the Colorado and the southern portion of the Cardium.

As at December 31, 2010, Penn West had a developed and undeveloped land base totalling approximately 3.3 million net acres in the Southern District.

In 2010, Penn West invested approximately $725 million of capital in this district and drilled 304 gross wells. The majority of capital was spent in the southern portion of the Cardium, Waskada and the Colorado resource plays.

Waskada Resource Play

Waskada is located in the area of Southwestern Manitoba near the Canada/U.S. border. In 2010, we focused on the assessment and development of the Lower Amaranth pool leading to $120 million of capital expenditures and a total of 83 gross wells drilled, of which 77 used horizontal multi-stage fracture technology. Penn West continued to accumulate lands in this tight, light-oil play and held 75,000 net acres of developed and undeveloped land as at December 31, 2010. In 2011, Penn West anticipates a high level of activity in this area with capital spending of approximately $140 to $175 million planned, including facility upgrades to accommodate higher production levels and an expected 80 to 110 well drilling program.

Colorado Resource Play

The Colorado resource play is located in Western Saskatchewan and East Central Alberta and is divided into two distinct plays: the Viking oil play in Saskatchewan, and a combined oil and natural gas play, with a high portion of liquids production, in Eastern Alberta. Penn West has a significant land position in this play of approximately 760,000 net acres of developed and undeveloped land at December 31, 2010. In 2010, Penn West spent $185 million drilling a total of 69 gross horizontal multi-stage fracture oil wells predominantly on the Saskatchewan side of the play. In addition, another 26 gross horizontal multi-stage fracture wells were drilled in the gassy oil side of this play in Alberta. Penn West is in the early stages of its work on this play with approximately 50 percent of its 2011 drilling program focused on assessment and appraisal work. In 2011, Penn West plans to spend approximately $80 to $100 million of capital on the Colorado resource play including the planned drilling of approximately 75 to 90 wells with a focus on its oil prospects.

Cardium Resource Play (Southern Portion)

The Cardium resource play is located in West Central Alberta and extends between Calgary and Grande Prairie, Alberta. The Southern portion of this play is included in Penn West's Southern District. At December 31, 2010, Penn West had approximately 250,000 net acres of developed and undeveloped land in this resource play. Penn West's holdings in the Cardium, include, among others, lands in the Willesden Green and Pembina areas. In 2010, Penn West spent approximately $85 million in the southern portion of the Cardium and drilled a total of 10 gross multi-stage horizontal wells. In 2011, Penn West has allocated approximately $150 million of capital to the southern portion of the Cardium and plans to drill approximately 40 wells.

Penn West initiated a CO_2 flood pilot project for enhanced oil recovery in the Pembina area in early 2005 targeting the Cardium formation. The pilot project underwent expansion in 2008. In conjunction with the pilot work completed to date, Penn West continues to be in discussions with various parties regarding the supply of CO_2 to Penn West. We are also involved in numerous commercial CO_2 flood projects throughout Western Canada including the Joffre area in Alberta and the Weyburn and Midale areas in Saskatchewan.

Other Southern District Resource Plays

The Southern District includes a number of other plays outside of the three main resource plays highlighted above. Expenditures in 2010 with respect to these other plays included development and optimization opportunities in Penn West's legacy asset base in southeast Saskatchewan and continued participation in the Weyburn Unit. In early 2010, Penn West divested most of its interests in the Leitchville area of the Southern District as part of an exchange of properties. For more information regarding this disposition, see "Description of our Business – General Development of the Business – Year Ended December 31, 2010 – Asset Exchange Agreement".

Total expenditures in 2011 with respect to the resource plays in the Southern District (other than the Cardium, Amaranth and Colorado resource plays) are expected to be approximately $235 million. This includes projects in our heavy oil properties in western Saskatchewan, our non-operated interests primarily in the Weyburn area of Southeastern Saskatchewan, and other development and optimization programs in Southern Saskatchewan and Alberta.

Northern District

The Northern District encompasses Northeastern British Columbia, Northern Alberta, parts of West Central Alberta, and the Northwest Territories. In 2010, production volumes from this district averaged approximately 77,371 boe per day, comprised of approximately 42,022 barrels per day of liquids and 212 MMcf per day of natural gas. The main resource plays in the Northern District are the northern portion of the Cardium, the Carbonates, Cordova, and the heavy oil play represented by the Peace River Assets.

In 2010, capital investment by Penn West in the Northern District was approximately $465 million. The majority was focused on the northern portion of the Cardium resource play and in northwest Alberta on the Carbonates resource play. Penn West drilled 157 gross wells in this district throughout 2010 with a focus on its three main resource plays, being the Carbonates light-oil resource play, the Cordova natural gas shale play and the Peace River Assets.

As at December 31, 2010, Penn West had a developed and undeveloped land position of approximately 2.9 million net acres in the Northern District.

Cardium Resource Play (Northern Portion)

In 2010, Penn West spent approximately $95 million in capital in the northern portion of the Cardium and drilled a total of 25 gross multi-stage horizontal wells. Penn West had approximately 420,000 net acres of developed and undeveloped land in this resource play. In 2011, Penn West has allocated approximately $175 million of capital to the northern portion of the Cardium and plans to drill approximately 60 wells in this play.

Carbonates Resource Play

The Carbonates resource play is a tight, light-oil play situated north and northwest of Edmonton and extends through North-Central Alberta. Due to the nature of the legacy development in this area, Penn West's focus with respect to this play was on enhanced oil recovery until recent developments in horizontal multi-stage fracture technology. As at December 31, 2010, Penn West had a developed and undeveloped land position of approximately 195,000 net acres relating to the Carbonates resource play. In 2010, Penn West drilled 21 gross wells in this play and made a capital investment of approximately $194 million. In 2011, Penn West expects overall capital expenditures to total approximately $125 to $150 million for the play including the drilling of 30 to 40 wells.

Cordova Resource Play

The Cordova resource play is located in the most northern portion of Northeastern British Columbia in the Wildboy area. This play is a legacy Penn West exploration and development property targeting natural gas production that includes significant production infrastructure in place and all-weather access roads. This play was initially developed by Penn West in the late 1990's using vertical drilling technology. The play area includes a natural gas plant and sales pipeline that connects to the TransCanada pipeline system in Alberta and is now 50 percent owned and operated by Penn West under the Cordova JV.

Penn West's focus for growth in this area is the shale gas play in the Cordova Embayment, located east of the Horn River development. In September 2010, the Cordova JV was formed to accelerate both the appraisal and development of these assets. Penn West had a total of approximately 175,000 net acres of developed and undeveloped land in the area at December 31, 2010. In 2010, Penn West drilled two stratigraphic test wells and also flow tested a well to collect data. In 2011, together with the Mitsubishi Affiliate under the Cordova JV, Penn West expects to continue the evaluation of the play area, including a planned 15 to 20 well drilling program and expected capital expenditures of approximately $140 to $160 million for a total of $35 to $40 million of expenditures by Penn West, with the remaining amount to be contributed by the Mitsubishi Affiliate.

For more information regarding the Cordova JV, see "Description of our Business – General Development of the Business – Year Ended December 31, 2010 - Joint Venture with Affiliate of Mitsubishi Corporation".

Peace River Assets

The Peace River Assets are a significant bitumen play located on oil sands leases in the Peace River area of Northwestern Alberta. In June 2010, Penn West and the CIC Affiliate formed PROP to increase the pace of development of Penn West's bitumen resources in the area, and under this partnership, Penn West has retained a 55 percent interest in the Peace River Assets, with the CIC Affiliate holding the remaining 45 percent interest. For more information regarding the Peace River Assets and PROP, see "Description of our Business – General Development of the Business – Year Ended December 31, 2010 - Joint Venture and Equity Financing with Affiliate of China Investment Corporation".

PROP has a strong land position in this play comprised of approximately 310,000 net acres of developed and undeveloped land at December 31, 2010. In 2010, a total of 21 gross wells, including 13 horizontal producing wells and eight stratigraphic test wells, were drilled in the area. In 2011, PROP plans to continue its resource assessment with expected drilling of approximately 55 stratigraphic test wells and 20 to 25 primary production horizontal wells. Additionally, in 2010, regulatory approval was received allowing PROP to conduct a Cyclic Steam Injection pilot project in the area of the Peace River Assets, with such injection expected to commence in the first half of 2011.

Other Northern District Resource Plays

Capital expenditures in the Northern District excluding the above three resource plays are expected to total approximately $80 million in 2011. As the outlook for natural gas prices remains weak relative to oil prices, Penn West plans to focus on light-oil areas in 2011 and the optimization of existing core properties.

Additional Information

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

We do not have any material properties to which reserves have been attributed which are capable of producing but which are not producing. For a discussion of our 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, 2010.

	Producing				Non-Producing		Total	
	Oil		Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	11,163	6,258	10,099	4,309	7,529	3,980	28,791	14,547
British Columbia	143	49	982	371	388	78	1,513	498
Saskatchewan	7,779	5,055	1,197	681	3,091	1,465	12,067	7,201
Manitoba	783	402	1	-	212	109	996	511
Northwest Territories	3	-	7	1	38	7	48	8
Wyoming	-	-	301	124	50	17	351	141
Montana	3	-	-	-	-	-	3	-
North Dakota	16	6	1	-	-	-	17	6
Total	19,890	11,770	12,588	5,486	11,308	5,656	43,786	22,912

Properties with no Attributed Reserves

The following table sets out the unproved properties in which we have an interest as at December 31, 2010.

	Unproved Properties (thousands of acres)	
	Gross	Net
Alberta	1,556	1,242
British Columbia	674	229
Saskatchewan	429	356
Manitoba	225	220
Northwest Territories	91	19
North Dakota	21	19
Wyoming	15	8
Montana	1	-
Total	3,012	2,093

We currently have no material work commitments on these lands. The primary lease or extension term on approximately 298,000 net acres of unproved property is scheduled to expire by December 31, 2011. The right to explore, develop and exploit these leases will be surrendered unless we qualify them for continuation based on production, drilling or technical mapping.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

The development of properties with no attributed reserves can be affected by a number of factors including, but not limited to, project economics, forecasted price assumptions, cost estimates and access to infrastructure. These and other factors could lead to the delay or the acceleration of projects related to these properties.

Tax Horizon

The most important variables that will determine the level of cash taxes incurred by us in a given year will be the price of crude oil and natural gas, our capital spending levels and the amount of tax pools available to us. We currently estimate that we will not be required to pay income taxes until at least the 2015 taxation year. However, if crude oil and natural gas prices were to strengthen beyond the levels anticipated by the current forward market, our tax pools would be utilized more quickly and we may experience higher than expected cash taxes or payment of such taxes in an earlier time period. However, we emphasize that it is difficult to give guidance on future taxability as we operate within an industry where various factors constantly change our outlook, including factors such as acquisitions, divestments, capital spending levels, dividend levels and commodity price changes.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2010, irrespective of whether such costs were capitalized or charged to expense when incurred.

	2010 MM$
Property Acquisition Costs[1]	
Proved Properties	(1,306)
Unproved Properties	102
Exploration Costs[1]	210
Development Costs[1]	881
Corporate Costs	11
Total Capital Expenditures	(102)
Corporate Acquisitions	139
Total Expenditures	37

Note:

(1) "Property Acquisition Costs", "Exploration Costs" and "Development Costs" have the meanings ascribed thereto in the COGE Handbook.

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, 2010.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	4	2	347	243
Natural Gas	10	8	43	30
Service	10	10	9	9
Stratigraphic test	1	1	34	14
Dry	-	-	3	2
Total	25	21	436	298

We currently estimate that our capital expenditures in 2011 will be between $1.1 billion and $1.2 billion in order to execute our current 2011 capital programs. The primary components of our programs are described under the heading "Other Oil and Gas information – Description of Our Properties, Operations and Activities in Our Major Operating Regions".

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2011 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 Oil Equivalent (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved										
Developed Producing	63,102	52,861	17,666	15,315	318,355	275,882	9,262	6,773	143,090	120,930
Proved Developed										
Non- Producing	1,039	894	754	704	10,671	9,137	164	137	3,736	3,258
Proved Undeveloped	10,427	9,455	133	124	18,111	16,239	668	618	14,247	12,903
Total Proved	74,568	63,209	18,554	16,144	347,137	301,258	10,095	7,528	161,073	137,091
Total Probable	6,202	5,313	1,039	820	32,789	27,406	630	500	13,338	11,202
Total Proved Plus Probable	80,770	68,522	19,594	16,965	379,927	328,664	10,725	8,028	174,410	148,293

No one field (being a defined geographical area consisting of one or more pools) accounts for more than five percent of the estimated production disclosed above. For more information, see "Other Oil and Gas Information – Description of Our Properties, Operations and Activities in Our Major Operating Regions".

Production History

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

	Quarter Ended 2010				Year Ended December 31, 2010
	March 31	June 30	September 30	December 31	
Share of Average Gross Daily Production					
Light and Medium Crude Oil (bbl/d)	65,948	64,989	68,016	77,054	69,030
Heavy Oil (bbl/d)	19,883	18,579	17,766	16,849	18,260
Gas (MMcf/d)	410	408	394	365	394
NGLs (bbl/d)	10,486	12,209	12,598	11,393	11,676
Combined (boe/d)	164,587	163,700	164,087	166,148	164,633
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	75.75	71.32	69.98	74.63	72.96
Heavy Oil ($/bbl)	64.31	57.03	58.81	61.87	60.55
Gas ($/Mcf)	5.46	3.83	3.68	3.79	4.20
NGLs ($/bbl)	53.67	48.44	42.47	46.83	47.58
Combined ($/boe)	55.12	47.94	47.48	52.43	50.74
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	13.94	13.21	13.47	13.64	13.57
Heavy Oil ($/bbl)	9.65	8.31	8.25	8.61	8.73
Gas ($/Mcf)	0.86	0.52	0.48	0.42	0.58
NGLs ($/bbl)	17.12	14.49	12.83	14.79	14.69
Combined ($/boe)	9.99	8.57	8.60	9.14	9.07

	Quarter Ended 2010				Year Ended December 31, 2010
	March 31	June 30	September 30	December 31	
Production Costs[1][2]					
Light and Medium Crude Oil ($/bbl)	21.23	20.90	20.68	19.39	20.50
Heavy Oil ($/bbl)	16.50	17.50	17.32	17.28	17.14
Gas ($/Mcf)	1.63	1.62	1.71	1.88	1.71
NGLs ($/bbl)	16.46	16.11	15.95	15.07	15.89
Combined ($/boe)	15.61	15.52	15.78	15.92	15.71
Transportation					
Light and Medium Crude Oil ($/bbl)	-	-	-	-	-
Heavy Oil ($/bbl)	0.09	0.09	0.10	0.11	0.09
Gas ($/Mcf)	0.22	0.22	0.22	0.23	0.22
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	0.56	0.55	0.55	0.52	0.55
(Gain)/Loss on Risk Management Contracts					
Light and Medium Crude Oil ($/bbl)	2.93	2.83	2.00	4.73	3.18
Heavy Oil ($/bbl)	-	-	-	-	-
Gas ($/Mcf)	(0.22)	(0.54)	(0.59)	(0.31)	(0.42)
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	0.62	(0.22)	(0.58)	1.51	0.34
Netback Received[3]					
Light and Medium Crude Oil ($/bbl)	35.03	31.36	30.86	34.64	33.02
Heavy Oil ($/bbl)	38.07	31.13	33.14	35.87	34.59
Gas ($/Mcf)	2.97	2.01	1.86	1.57	2.11
NGLs ($/bbl)	36.55	33.95	29.64	32.04	32.88
Combined ($/boe)	28.34	23.52	23.13	25.34	25.07

Notes:

(1) 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.

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

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

During the year ended December 31, 2010, Penn West produced 60 MMboe, comprised of 25 MMbbl of light and medium oil, 7 MMbbl of heavy oil, 144 MMcf of natural gas and 4 Mbbl of natural gas liquids.

Marketing Arrangements

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

Oil and Liquids Marketing

Of our liquids production, approximately 70 percent is light and medium oil, 18 percent is conventional heavy oil and 12 percent is NGLs. In regard specifically to crude oil, our average quality is 30.8 degrees API, which is comprised of an average quality for our light and medium oil of 35.3 degrees API and an average quality for our conventional heavy oil of 13.5 degrees API.

To reduce risk, we market the majority of our production to large credit-worthy counter-parties or end-users on varying term contracts 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 (including NGLs) and our conventional heavy oil, before adjustments for hedging activities, for the periods indicated:

	2010		2009	
Quarter ended	**Light and Medium Oil and NGLs ($/bbl)**	**Heavy Oil ($/bbl)**	**Light and Medium Oil and NGLs ($/bbl)**	**Heavy Oil ($/bbl)**
March 31	72.72	64.31	44.50	36.92
June 30	67.70	57.03	58.11	56.71
September 30	65.68	58.81	64.15	58.72
December 31	71.05	61.87	69.49	62.97

Natural Gas Marketing

In 2010, we received an average price from the sale of natural gas, before adjustments for hedging activities, of $4.20/Mcf compared to $4.13/Mcf realized in 2009. Approximately 90 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 which is one of the largest and most liquid market hubs in North America. In addition to maximizing netbacks, the current portfolio approach also enhances our 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 approximately two percent of sales.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. In accordance with policies approved by our Board of Directors, we may, from time to time, manage these risks through the use of swaps, collars or other financial instruments. Commodity price risk may be hedged up to a maximum of 50 percent of forecast sales volumes, net of royalties, for the balance of any current year and one year following and up to 25 percent of forecast sales volumes, net of royalties, for one additional year thereafter. This policy is reviewed by management and our Board of Directors from time to time and amended as necessary.

We are also exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our hedging portfolio among a number of counterparties, primarily parties within our banking syndicate, whom we consider to be financially sound. For information in relation to marketing arrangements, see "Other Oil and Gas Information – Marketing Arrangements".

As at December 31, 2010, we were not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which we 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 agreements disclosed by us in Note 10 to our audited consolidated financial statements as at and for the year ended December 31, 2010, which have been filed on SEDAR at www.sedar.com.

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, as disclosed herein.

APPENDIX B

MANDATE OF THE AUDIT COMMITTEE

1. PURPOSE

The purpose of the Audit Committee (the " **Committee**") of the board of directors (the " **Board**") of Penn West Petroleum Ltd. (" **Penn West**") is to assist the Board in fulfilling its responsibility for oversight of the integrity of Penn West's consolidated financial statements, Penn West's compliance with legal and regulatory requirements, the qualifications and independence of Penn West's independent auditors, and the performance of Penn West's internal audit function, if any.

The objectives of the Committee are as follows:

(a) To assist the Board in meeting its responsibilities (especially for accountability) in respect of the preparation and disclosure of the consolidated financial statements of Penn West and related matters;

(b) To provide better communication between directors and independent auditors;

(c) To assist the Board in meeting its responsibilities regarding the oversight of the independent auditor's qualifications and independence;

(d) To assist the Board in meeting its responsibilities regarding the oversight of the credibility, integrity and objectivity of financial reports;

(e) To strengthen the role of the non-management directors by facilitating discussions between directors on the Committee, management and independent auditors;

(f) To assist the Board in meeting its responsibilities regarding the oversight of the performance of Penn West's independent auditors and internal audit function (if any); and

(g) To assist the Board in meeting its responsibilities regarding the oversight of Penn West's compliance with legal and regulatory requirements.

2. SPECIFIC DUTIES AND RESPONSIBILITIES

Subject to the powers and duties of the Board, the Committee will perform the following duties:

(a) Satisfy itself on behalf of the Board that Penn West's internal control systems are sufficient to reasonably ensure that:

  (i) controllable, material business risks are identified, monitored and mitigated where it is determined cost effective to do so;

  (ii) internal controls over financial reporting are sufficient to meet the requirements under National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* and the *United States Securities Exchange Act of 1934* , as amended, and

  (iii) there is compliance with legal, ethical and regulatory requirements.

(b) Review the annual and interim financial statements of Penn West prior to their submission to the Board for approval. The process should include, but not be limited to:

  (i) review of changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

  (ii) review of significant accruals, reserves or other estimates such as the ceiling test calculation;

  (iii) review of accounting treatment of unusual or non-recurring transactions;

  (iv) review of compliance with covenants under loan agreements;

(v) review of asset retirement obligations recommended by the Health, Safety, Environment and Regulatory Committee;

(vi) review of disclosure requirements for commitments and contingencies;

(vii) review of adjustments raised by the independent auditors, whether or not included in the financial statements;

(viii) review of unresolved differences between management and the independent auditors, if any;

(ix) review of reasonable explanations of significant variances with comparative reporting periods; and

(x) determination through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed.

(c) Review, discuss and recommend for approval by the Board the annual and interim financial statements and related information included in prospectuses, management discussion and analysis, information circular-proxy statements and annual information forms, prior to recommending Board approval.

(d) Discuss Penn West's interim 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).

(e) With respect to the appointment of independent auditors by the Board, the Committee shall:

(i) on an annual basis, review and discuss with the auditors all relationships the auditors have with Penn West to determine the auditors' independence, 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;

(ii) be directly responsible for 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 Penn West, including the resolution of disagreements between management and the independent auditor regarding financial reporting, and the independent auditors shall report directly to the Committee;

(iii) review and evaluate the performance of the lead partner of the independent auditors;

(iv) 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;

(v) 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;

(vi) 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

(vii) 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.

(f) The Committee may delegate to one or more members of the Committee authority to pre-approve non-audit services in satisfaction of 2(e)(vii) above 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:

(i) the pre-approval policies and procedures are detailed as to the particular service;

(ii) the Committee is informed of each non-audit service so approved; and

(iii) the procedures do not include delegation of the Committee's responsibilities to management;

provided that in order for the pre-approval requirements to be satisfied for any non-audit services that are not pre-approved in accordance with the procedures set forth above:

(iv) the aggregate amount of all non-audit services that were not pre-approved (if any) must be reasonably expected to constitute no more than 5% of the total amount of fees paid by Penn West and its subsidiary entities to the auditors during the fiscal year in which the services are provided;

(v) Penn West or the subsidiary entity, as the case may be, must not have recognized the services as non-audit services at the time of the engagement; and

(vi) the services must have been 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.

(g) At least annually, obtain and review 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.

(h) 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.

(i) At least annually, obtain and review a report by the independent auditors describing (i) all critical accounting policies and practices used by Penn West, (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.

(j) 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.

(k) Review, set and approve hiring policies relating to current and former staff of current and former independent auditors.

(l) 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).

(m) Review all pending significant litigation to ensure disclosures are sufficient and appropriate.

(n) Satisfy itself that adequate procedures are in place for the review of Penn West's public disclosure of financial information from Penn West's financial statements and periodically assess the adequacy of those procedures.

(o) Review and discuss major financial risk exposures and the steps management has taken to monitor and control such exposures.

(p) Establish procedures independent of management for:

(i) the receipt, retention and treatment of complaints received by Penn West regarding accounting, internal accounting controls, or auditing matters; and

(ii) the confidential, anonymous submission by employees of Penn West of concerns regarding questionable accounting or auditing matters.

(q) 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.

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

(s) Review management's monitoring of Penn West's compliance with the organization's Code of Business Conduct and Ethics and Code of Conduct for Senior Officers and Senior Financial Management.

(t) Review and discuss with the Chief Executive Officer, the Chief Financial Officer 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 Chief Executive Officer and the Chief Financial Officer.

(u) Review and discuss major issues regarding accounting principles and financial statement presentations, including any significant changes in Penn West's selection or application of accounting principles.

(v) Review and discuss major issues as to the adequacy of Penn West's internal controls and any special audit steps adopted in light of material control deficiencies.

(w) 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.

(x) Review and discuss the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on Penn West's financial statements.

(y) 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.

(z) annually review the Committee's Mandate and the Committee Chair's Terms of Reference and recommend any proposed changes to the Board for consideration; and

(aa) review and approve any other matters specifically delegated to the Committee by the Board.

3. KNOWLEDGE & EDUCATION

Committee members shall be "financially literate" within the meaning of NI 52-110, and should have or obtain sufficient knowledge of Penn West's financial and audit policies and procedures to assist in providing advice and counsel on related matters. Members shall be encouraged as appropriate to attend relevant educational opportunities at the expense of Penn West.

4. COMPOSITION

(a) The Committee shall be composed of at least three members of the Board or such greater number as the Board may from time to time determine.

(b) Committee members shall be appointed and removed by the Board.

(c) Each member of the Committee shall be an "independent" director in accordance with the definition of "independent" in (a) National Instrument 52-110 *Audit Committees* ("**NI 52-110**") and (b) Section 303A.02 and 303A.07(b) of the Corporate Governance Rules of the New York Stock Exchange.

(d) 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 Penn West'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.

(e) 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 committees of more than three public companies. To the extent that any proposed nominee for membership on the Committee serves on the audit committees 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 Penn West's annual proxy information circular and annual report on Form 40-F filed with the United States Securities and Exchange Commission.

5. MEETINGS

(a) The Committee shall meet at least four times per year at the call of the Committee Chair. The Committee Chair may call additional meetings as required. In addition, a meeting may be called by the Chairman of the Board, the Chief Executive Officer, the Executive Vice President & Chief Financial Officer, the President & Chief Operating Officer or any member of the Committee.

(b) 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 shall meet with the independent auditors and management quarterly to review Penn West's interim financials. The Committee shall also meet with management and independent auditors on an annual basis to review and discuss Penn West's annual financial statements and the management's discussion and analysis of financial conditions and results of operations.

(c) Notice of the time and place of every meeting may be given orally, in writing, by facsimile or by other electronic means of communication to each member of the Committee at least 48 hours prior to the time fixed for such meeting. A member may, in any manner, waive notice of the meeting. Attendance of a member at a meeting shall constitute waiver of notice.

(d) A quorum shall be a majority of the members of the Committee.

(e) Committee meetings may be held in person, by video conference, by teleconference or by combination of any of the foregoing.

(f) As part of each Committee meeting the Committee members will also meet "in-camera" without any members of management present.

(g) The Committee Chair shall be a full voting member of the Committee.

(h) If the Committee Chair is unavailable or unable to attend a meeting of the Committee, the Committee Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen to preside over the meeting by a majority of the members of the Committee present at such meeting.

(i) The Chair of any Committee meeting (including, without limitation, any Chair selected in accordance with paragraph (g) above)) shall have a casting vote in the event of a tie on any matter upon which the Committee votes during such meeting.

(j) The Committee shall have the right to determine who shall and who shall not be present at any time during a meeting of the Committee. However, independent directors, including the Chairman of the Board, shall always have the right to be present.

(k) Agendas, with input from management and the Committee Chair, shall be circulated by the Committee Secretary to Committee members and relevant members of management along with appropriate meeting materials and background reading on a timely basis prior to Committee meetings.

6. MINUTES

(a) The secretary to the Committee (the "**Committee Secretary**") will be either the Corporate Secretary of the Company or his/her delegate. The Committee Secretary shall record and maintain minutes of the meetings of the Committee.

(b) Minutes of Committee meetings shall be approved by the Committee and maintained with Penn West's records by the Committee Secretary or designate.

7. REPORTING / AUTHORITY

(a) 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.

(b) Supporting schedules and information reviewed by the Committee shall be available for examination by any member of the Board.

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

(d) 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.

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

(f) 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.

8. ACCOUNTABILITY

The Committee's performance shall be evaluated by the Board as part of the Board assessment process established by the Governance Committee and the Board.

9. RESOURCES

(a) The Committee may retain special legal, accounting, financial or other consultants or advisors to advise the Committee at Penn West's expense and shall have sole authority to retain and terminate any such consultants or advisors and to approve any such consultant's or advisor's fees and retention terms, subject to review by the Board.

(b) The Committee shall have access to Penn West's senior management and documents as required to fulfill its responsibilities and shall be provided with the resources necessary to carry out its responsibilities.

(c) The Chief Executive Officer and the Chief Financial Officer, or their designates, shall be available to attend meetings of the Committee.

(d) Such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee, the Chief Executive Officer or the Chief Financial Officer.

(e) The Committee may, by specific invitation, have other resource persons in attendance to assist in the discussion and consideration of matters relating to the Committee.

10. DELEGATION

The Committee may delegate from to time to any person or committee of persons any of the Audit Committee's responsibilities that are permitted to be delegated to such person or committee in accordance with applicable laws, regulations and stock exchange requirements.

11. STANDARDS OF LIABILITY

(a) Nothing contained in this Mandate is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities, subject to applicable statutory, regulatory and other legal requirements.

(b) The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the year ended December 31, 2010

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", "We" or "Our") for the years ended December 31, 2010 and 2009. The date of this MD&A is March 17, 2011.

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

On January 1, 2011, we completed our plan of arrangement under which Penn West converted from an income trust to a corporation, Penn West Petroleum Ltd. (the "Company"), which is operating under the trade name of Penn West Exploration. These consolidated financial results are presented under Penn West's former structure, as an income trust, as at and for the years ended December 31, 2010 and 2009.

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 the MD&A. Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Measures including funds flow, funds flow per unit-basic, funds flow per unit-diluted, netback, net debt, payout ratio, return on equity and return on capital 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. Funds flow is cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Funds flow is used to assess our ability to fund dividend and planned capital programs. See below for reconciliations of funds flow to its nearest measure prescribed by GAAP. Netback is a per-unit-of-production measure of operating margin used in capital allocation decisions and to economically rank projects. Operating margin is calculated as revenue less royalties, operating costs and transportation costs and is used for similar purposes to netback. Net debt is the sum of long-term debt, convertible debentures and working capital (excluding risk management and future income taxes) and is used to assess our leverage levels and hence the continuing appropriateness of our dividend and capital investment levels. Payout ratio is calculated as distributions paid divided by funds flow and is used to assess the adequacy of funds flow retained to finance capital programs. Return on equity is the rate of return calculated by comparing net income to unitholders equity. Return on capital is calculated using net income and financing charges compared to unitholder equity and long-term debt and is used to assess how effectively Penn West utilizes capital.

Calculation of Funds Flow

	Year ended December 31	
(millions, except per unit amounts)	**2010**	2009
Cash flow from operating activities	**$ 1,217**	$ 1,401
Increase (decrease) in non-cash working capital	**(85)**	27
Asset retirement expenditures	**53**	65
Funds flow	**$ 1,185**	$ 1,493
Basic per unit	**$ 2.68**	$ 3.62
Diluted per unit	**$ 2.65**	$ 3.60

Annual Financial Summary

(millions, except per unit amounts)	Year ended December 31 **2010**	2009	2008
Gross revenues [1]	**$ 3,034**	$ 3,203	$ 4,651
Funds flow	**1,185**	1,493	2,537
Basic per unit	**2.68**	3.62	6.75
Diluted per unit	**2.65**	3.60	6.66
Net income (loss)	**226**	(144)	1,221
Basic per unit	**0.51**	(0.35)	3.25
Diluted per unit	**0.50**	(0.35)	3.22
Capital expenditures, net [2]	**1,187**	688	1,095
Long-term debt at year-end	**2,496**	3,219	3,854
Convertible debentures	**255**	273	296
Distributions paid [3]	**708**	910	1,500
Total assets	**$ 13,368**	$ 13,876	$ 15,412

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Excludes business combinations and net proceeds on property acquisitions and dispositions.
(3) Includes distributions paid and reinvested in trust units under the distribution reinvestment plan.

2010 Highlights

- Production averaged 164,633 boe per day and was weighted 60 percent to liquids and 40 percent to natural gas.
- Net debt was reduced by approximately $536 million during 2010.
- Capital expenditures for 2010, net, totalled $1,187 million including $102 million of strategic land acquisitions to further strengthen our position in key resource plays and excluding $17 million of joint venture carried capital. Net property dispositions were $1,306 million in 2010 compared to $369 million in 2009.
- Funds flow for 2010 was $1,185 million compared to $1,493 million in 2009. The decrease was primarily due to lower realized risk management gains.
- Net income was $226 million compared to a net loss of $144 million for 2009. The increase was primarily due to higher oil and natural gas revenues and lower unrealized risk management losses.
- Netback was $25.07 per boe compared to $26.32 per boe in 2009.

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

Three months ended	**Dec. 31 2010**	Sep. 30 2010	June 30 2010	Mar. 31 2010	Dec. 31 2009	Sep. 30 2009	June 30 2009	Mar. 31 2009
Gross revenues [1]	**$ 782**	$ 728	$ 718	$ 806	$ 831	$ 800	$ 791	$ 781
Funds flow	**305**	267	269	344	366	349	430	348
Basic per unit	**0.67**	0.59	0.62	0.81	0.87	0.84	1.05	0.87
Diluted per unit	**0.66**	0.58	0.61	0.80	0.86	0.83	1.05	0.87
Net income (loss)	**(21)**	(25)	195	77	(12)	7	(41)	(98)
Basic per unit	**(0.05)**	(0.06)	0.45	0.18	(0.03)	0.02	(0.10)	(0.25)
Diluted per unit	**(0.05)**	(0.06)	0.44	0.18	(0.03)	0.02	(0.10)	(0.25)
Distributions declared	**123**	177	196	190	189	188	188	276
Per unit	**$ 0.27**	$ 0.39	$ 0.45	$ 0.45	$ 0.45	$ 0.45	$ 0.45	$ 0.69
Production								
Liquids (bbls/d) [2]	**105,296**	98,380	95,777	96,317	101,636	104,583	104,070	105,643
Natural gas (mmcf/d)	**365**	394	408	410	411	441	459	447
Total (boe/d)	**166,148**	164,087	163,700	164,587	170,164	178,124	180,601	180,096

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

Financial Markets

Throughout 2010, the global financial markets experienced signs of recovery but remain volatile due to a slower than expected U.S. economic recovery and ongoing concerns about the sovereign debt of several European countries. This led to financial assistance and fiscal easing measures in the U.S. and Europe in an effort to promote economic growth and job creation. In contrast, Asia and many of the world's developing economies have returned to growth levels similar to those experienced before the recent economic crisis prompting China, in particular, to begin fiscal tightening measures.

In early 2011, political tension in some North African and Middle Eastern countries resulted in upward pressure on crude oil prices with WTI trading over US$100.00 and Brent trading over US$115.00. Protests and similar activities in these regions have led to concerns regarding the possibility of supply disruptions of crude oil.

The March 11, 2011 earthquake and subsequent tsunami in Japan could impact energy markets. In the near term, demand for LNG and refined products such as heating oil and diesel are expected to increase, while demand for crude oil is expected to decline as significant refining capacity will likely for a time be offline in Japan. Over the longer term, demand for all energy products is expected to increase once the rebuilding process begins.

Commodity Markets

Global demand growth for crude oil exceeded increases in non-OPEC supply in 2010. The high demand from Asia and the developing economies of the world reduced OPEC's spare capacity resulting in price levels which support capital investment in oil development. This is evidenced by a year-over-year doubling of active rigs targeting oil in the United States. Demand growth for energy in North America and Europe remains weaker than in Asia and the developing economies.

Natural gas demand remained high in Asia and Europe over the past year resulting in premium prices in these markets compared to North America. North American natural gas markets continue to be oversupplied as lower prices have not led to a large enough reduction in drilling activity. Many producers continue to drill to retain their lease rights.

Crude Oil

In 2010, WTI crude oil prices averaged US$79.55 per barrel compared to US$61.93 per barrel in 2009. Canadian producers experienced delays in the second half of 2010 delivering their production to market due to certain pipeline failures that occurred on the Enbridge system. Crude supply continues to be apportioned as Enbridge works to return its pipelines to full operation and reduce high inventory levels resulting from these service interruptions. As a result, it has been challenging for some producers to deliver their production to market and in some situations has resulted in discounting certain Canadian streams and shut-ins of production. It is anticipated that these pipeline capacity issues will be resolved in the upcoming months.

Our average liquids price before the impact of the realized portion of risk management for 2010 was $67.68 per barrel. Currently, we have risk management contracts of 41,000 barrels per day for the remainder of our 2011 crude oil production at average prices between US$79.98 per barrel and US$96.39 per barrel and 25,000 barrels per day of our forecasted 2012 crude oil production between US$84.40 per barrel and US$104.01 per barrel.

Natural Gas

In 2010, the AECO Monthly Index averaged $4.12 per mcf compared to $4.13 per mcf in 2009. Natural gas prices remained weak throughout 2010 and drilling activity for shale gas, primarily in the U.S., continued notwithstanding the low prices. This drilling activity persisted for several reasons, most notably, producers drilling to retain leases, producers receiving enhanced value from the high natural gas liquids content of some shale gas plays and the infusion of joint venture capital from foreign partners. This led to production rates increasing year-over-year without a significant increase in demand resulting in inventory levels at or near record highs throughout most of 2010. Recent cold weather has contributed to storage levels near the five-year average levels.

Our corporate average natural gas price before the impact of the realized portion of risk management was $4.20 per mcf for 2010. We currently have no natural gas risk management contracts for 2011 or beyond.

Business Strategy

On January 1, 2011, we converted to an exploration and production ("E&P") company. Moving forward we anticipate a level of return for our shareholders to include an element of both growth and yield.

Over the past few years we have been building towards our corporate conversion and have executed a number of strategies in advance of our conversion date. These strategies include a thorough evaluation of our asset base including our resource plays, acquisition and divestiture activity in order to focus our asset base and to create efficiencies, a build-up of our drilling locations inventory which is now over 8,000 including approximately 3,800 specific locations, the strengthening of our balance sheet through debt reduction, debt diversification and distribution reductions and the enhancement of our staff and technical expertise including exploration, to enable a significant increase to our operating activities.

Throughout 2010, we were active in strengthening our balance sheet and diversifying our debt portfolio along with accessing capital through the close of two strategic joint ventures. We completed transactions to this end including the following:

- In January, we closed an asset swap (the "January 2010 asset swap") that increased our position in our Pembina and Dodsland light-oil plays in exchange for certain interests in the Leitchville area. We also received net cash consideration of $434 million, prior to closing adjustments.
- In March, we completed a private placement of senior unsecured notes with an aggregate principal amount of approximately US$250 million and CAD$50 million.
- In April, we closed the renewal of our unsecured, revolving syndicated bank facility for three years with an aggregate borrowing amount of $2.25 billion.
- In June, we formed a joint venture partnership (the "Peace River Oil Partnership") to develop oil resources in the Peace River area in northern Alberta. As a result of the arrangement, we contributed assets to the partnership for a 55 percent interest and received $817 million which included cash of $312 million and a commitment of $505 million to fund our future capital and operating expenses. In addition, we closed a private placement issuing 23.5 million trust units for gross proceeds of $435 million ($424 million net).
- In September, we formed a joint venture (the "Cordova Joint Venture") to develop our unconventional natural gas assets located in northeastern British Columbia. As a result of the arrangement, we sold a 50 percent interest in this property in exchange for approximately $250 million of cash and a commitment from our partner to fund $600 million of the first $800 million of capital expenditures.
- In December, we closed the first tranche of a private placement of senior unsecured notes with an aggregate principal amount of US$95 million and CAD$60 million. In January 2011, we closed the second tranche of the private placement for US$75 million. The aggregate principal amount of both tranches is approximately US$170 million and CAD$60 million.

In 2011 we plan to allocate approximately 90 percent of our capital program to our significant inventory of light-oil projects. We will continuously evaluate the results of our 2011 capital program and assess areas where the rate of development may be economically increased.

Performance Indicators

Our management and Board of Directors monitor our performance based upon a number of qualitative and quantitative factors including:

- Finding and development ("F&D") costs – We use these metrics to assess the economic viability and the stage of development of our resource plays.
- Base operations – This includes our production performance and execution of our operational, health, safety, environmental and regulatory programs.
- Shareholder value measures – This includes key metrics such as funds flow per share and dividends or distributions per share.
- Financial, business and strategic considerations – This includes the management of our asset base, balance sheet stewardship, execution of financial transactions and the overall goal of creating shareholder value (return on investment).

Finding and Development Costs

	Year ended December 31			
	2010	2009	2008	3-Year average
Adjusted FD&A including future development costs ("FDC") (1)				
FD&A costs per boe – proved plus probable	**$ 18.12**	$ 23.77	$ 23.38	$ 22.81
FD&A costs per boe – proved	**16.64**	15.11	30.78	26.93
Excluding FDC (2)				
F&D costs per boe – proved plus probable	**18.90**	13.75	18.94	17.40
F&D costs per boe – proved	**21.50**	16.10	27.17	21.49
Including FDC (3)				
F&D costs per boe – proved plus probable	**26.73**	16.12	24.57	22.90
F&D costs per boe – proved	**$ 28.01**	$ 16.19	$ 31.94	$ 25.51

(1) The calculation of FD&A includes the change in FDC, excluding the effect of economic revisions related to downward revisions of natural gas prices and land acquisition costs.
(2) The calculation of F&D excludes the change in FDC and excludes the effects of acquisitions and dispositions.
(3) The calculation of F&D includes the change in FDC and excludes the effects of acquisitions and dispositions.

Our exploration and development capital program increased during 2010 as we transitioned to an E&P company. We added approximately 72 million boe of proved plus probable reserves (excluding acquisitions and dispositions) as a result of our successful drilling program focused on our light-oil projects.

The future benefit of approximately $640 million raised from joint venture activities, in the form of carried capital, was not included in the Adjusted FD&A calculation, nor was this benefit included in FDC. Capital expenditures for 2010 have been reduced by $17 million related to joint venture carried capital (2009 – nil). We use Adjusted FD&A to assess the economic viability and the stage of development of our resource plays. F&D costs are calculated in accordance with National Instrument 51-101, which include the change in FDC, on a proved and proved plus probable basis. For comparative purposes we also disclose F&D costs excluding FDC.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Base Operations

Throughout 2010, our drilling results were generally consistent with our expectations as we increased our capital plan recognizing our continuing successful results at our light-oil resource plays and in anticipation of our conversion to an E&P company. During the year, we closed two strategic joint venture arrangements, the Peace River Oil Partnership and Cordova Joint Venture, which provide us with significant capital commitments from our partners and allow us to assess the resource potential and move into full-scale development in a shorter time-frame than we previously anticipated.

Shareholder Value Measures

	Year ended December 31		
	2010	2009	2008
Funds flow per unit	**$ 2.68**	$ 3.62	$ 6.75
Distributions paid per unit	**$ 1.62**	$ 2.23	$ 4.08
Ratio of year-end total long-term debt to annual funds flow	**2.1:1**	2.2:1	1.5:1

To implement our corporate strategy of providing shareholders with a return including both growth and yield, the distribution level was decreased to $0.09 per unit per month effective with the September 2010 distribution paid in October 2010. The funds not distributed will be redeployed to advance the development of our resource plays.

The total long-term debt to annual funds flow ratio decreased in 2010 due to a decline in our long-term debt balance. This was partially offset by a reduction in annual funds flow due to lower production volumes resulting from net dispositions.

Financial, Business and Strategic Considerations

	Year ended December 31		
	2010	2009	2008
Return on capital (1)	**3%**	-	15%
Return on equity (2)	**3%**	(2)%	19%
Total assets (millions)	**$ 13,368**	$ 13,876	$ 15,412

(1) Net income before financing charges divided by average unitholders' equity and average total debt.
(2) Net income divided by average unitholders' equity.

The return on capital and return on equity ratios in 2010 increased primarily due to higher net income in 2010 and a reduction in our total debt. During 2010, we significantly reduced the outstanding balance on our syndicated bank facility by executing the January 2010 asset swap, the Peace River Oil Partnership transaction, the Cordova Joint Venture, an equity offering completed in June 2010 to a private investor and by the issuance of senior, unsecured notes. Refer to the Business Strategy section above for more details.

RESULTS OF OPERATIONS

Production

	Year ended December 31		
Daily production	**2010**	2009	% change
Light oil and NGL (bbls/d)	**80,706**	78,011	3
Heavy oil (bbls/d)	**18,260**	25,962	(30)
Natural gas (mmcf/d)	**394**	440	(10)
Total production (boe/d)	**164,633**	177,221	(7)

Our production results for 2010 were strengthened by our successful drilling program. Our focus in 2010 was continuing the development of our key light-oil plays which led to higher light-oil production than the prior year. We drilled 319 net wells in 2010 primarily using horizontal multi-stage fracture technology, compared to 94 net wells in 2009.

The decrease in production volumes from 2009 was mainly due to net property dispositions that included the Lloydminster property disposition completed in November 2009 of approximately 6,000 boe per day, predominantly of heavy oil, the January 2010 asset swap of approximately 2,900 boe per day and the contribution of assets to the Peace River Oil Partnership and Cordova Joint Venture in 2010.

When economic to do so, we strive to maintain a strategic mix of liquids and natural gas production in order to reduce exposure to price volatility that can affect a single commodity. In 2010, crude oil and NGL production averaged 98,966 barrels per day (60 percent of production) and natural gas production averaged 394 mmcf per day (40 percent of production).

Average Sales Prices

	Year ended December 31		
	2010	2009	% change
Light oil and liquids (per bbl)	**$ 69.29**	$ 59.07	17
Risk management gain (loss) (per bbl) (1)	**(2.72)**	8.19	(100)
Light oil and liquids net (per bbl)	**66.57**	67.26	(1)
Heavy oil (per bbl)	**60.55**	53.75	13
Natural gas (per mcf)	**4.20**	4.13	2
Risk management gain (per mcf) (1)	**0.42**	0.69	(39)
Natural gas net (per mcf)	**4.62**	4.82	(4)
Weighted average (per boe)	**50.74**	44.11	15
Risk management gain (loss) (per boe) (1)	**(0.34)**	5.32	(100)
Weighted average net (per boe)	**$ 50.40**	$ 49.43	2

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

Netbacks

	Year ended December 31		
	2010	2009	% change
Light oil and NGL (1)			
Production (bbls/day)	**80,706**	78,011	3
Operating netback (per bbl):			
Sales price	**$ 69.29**	$ 59.07	17
Risk management gain (loss) (2)	**(2.72)**	8.19	(100)
Royalties	**(13.73)**	(10.78)	27
Operating costs	**(19.83)**	(19.93)	(1)
Netback	**$ 33.01**	$ 36.55	(10)
Heavy oil			
Production (bbls/day)	**18,260**	25,962	(30)
Operating netback (per bbl):			
Sales price	**$ 60.55**	$ 53.75	13
Royalties	**(8.73)**	(7.26)	20
Operating costs	**(17.14)**	(15.54)	10
Transportation	**(0.09)**	(0.06)	50
Netback	**$ 34.59**	$ 30.89	12
Total liquids			
Production (bbls/day)	**98,966**	103,973	(5)
Operating netback (per bbl):			
Sales price	**$ 67.68**	$ 57.74	17
Risk management gain (loss) (2)	**(2.22)**	6.14	(100)
Royalties	**(12.81)**	(9.90)	29
Operating costs	**(19.33)**	(18.83)	3
Transportation	**(0.02)**	(0.01)	100
Netback	**$ 33.30**	$ 35.14	(5)
Natural gas			
Production (mmcf/day)	**394**	440	(10)
Operating netback (per mcf):			
Sales price	**$ 4.20**	$ 4.13	2
Risk management gain (2)	**0.42**	0.69	(39)
Royalties	**(0.58)**	(0.75)	(23)
Operating costs	**(1.71)**	(1.57)	9
Transportation	**(0.22)**	(0.21)	5
Netback	**$ 2.11**	$ 2.29	(8)
Combined totals			
Production (boe/day)	**164,633**	177,221	(7)
Operating netback (per boe):			
Sales price	**$ 50.74**	$ 44.11	15
Risk management gain (loss) (2)	**(0.34)**	5.32	(100)
Royalties	**(9.07)**	(7.66)	18
Operating costs	**(15.71)**	(14.93)	5
Transportation	**(0.55)**	(0.52)	6
Netback	**$ 25.07**	$ 26.32	(5)

(1) Excluded from the netback calculation is $5 million of realized risk management gains related to our foreign exchange contracts which swap US dollar revenue at a fixed Canadian dollar rate.
(2) Gross revenues include realized gains and losses on commodity contracts.

Production Revenues

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

	Year ended December 31		
(millions)	**2010**	2009	2008
Light oil and NGL	**$ 1,965**	$ 1,920	$ 2,465
Heavy oil	**405**	509	747
Natural gas	**664**	774	1,439
Gross revenues [1]	**$ 3,034**	$ 3,203	$ 4,651

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

The decrease in revenue for 2010 from 2009 was mainly the result of lower realized risk management gains and the impact of net property dispositions which reduced production of heavy oil and natural gas. Light oil and NGL production increased, notwithstanding the January 2010 asset swap, as we focused our 2010 capital program on light-oil resource plays. For 2010, heavy oil production was 30 percent lower and natural gas production was 10 percent lower than 2009.

The decrease in gross revenues for 2009 from the comparative period in 2008 was mainly the result of lower commodity prices coupled with lower production volumes as we concentrated our asset base.

Reconciliation of decrease in Production Revenues

(millions)	
Gross revenues – January 1 – December 31, 2009	$ 3,203
Increase in light oil and NGL production	66
Decrease in light oil and NGL prices (including realized risk management)	(21)
Decrease in heavy oil production	(151)
Increase in heavy oil prices	47
Decrease in natural gas production	(80)
Decrease in natural gas prices (including realized risk management)	(30)
Gross revenues – January 1 – December 31, 2010	$ 3,034

Royalties

	Year ended December 31		
	2010	2009	2008
Royalties (millions)	**$ 545**	$ 495	$ 898
Average royalty rate [1]	**18%**	17%	18%
$/boe	**$ 9.07**	$ 7.66	$ 12.95

(1) Excludes effects of risk management activities.

In 2010, royalty rates and per boe amounts increased as a result of higher crude oil prices. Our royalty rate trended downward throughout 2010 due to new wells coming on production at a lower royalty rate under the new provincial royalty programs.

Royalty rates decreased in 2009 compared to 2008 due to the effect of the new Alberta royalty programs that became effective for part of 2009. The royalties per boe amount decreased as a result of lower royalty payments due to lower commodity prices.

Expenses

(millions)	Year ended December 31 2010	2009	2008
Operating	**$ 944**	$ 966	$ 854
Transportation	**33**	34	34
Financing	**174**	161	204
Unit-based compensation	**$ 55**	$ 52	$ 45

(per boe)	Year ended December 31 2010	2009	2008
Operating	**$ 15.71**	$ 14.93	$ 12.31
Transportation	**0.55**	0.52	0.49
Financing	**2.89**	2.49	2.94
Unit-based compensation	**$ 0.92**	$ 0.81	$ 0.65

Operating

In 2010, acquisition and divestiture activity contributed to an increase in the operating costs per boe. Operating costs for 2010 include a realized loss on electricity contracts of $14 million (2009 - $16 million loss and 2008 - $6 million gain). We have contracts in place that fix the price on approximately 90 percent of our electricity consumption for 2011 at US$63.16 per MWH.

The rise in operating costs in 2009 compared to 2008 was due to greater 2009 emphasis on production maintenance activities to maintain production volumes. Due to the weak commodity price environment early in 2009, we reduced our capital program during that year and focused on highly efficient methods of maintaining production.

Financing

The Company has a three-year, unsecured, revolving syndicated bank facility with an aggregate borrowing limit of $2.25 billion. The facility expires on April 30, 2013 and is extendible. The credit facility contains provisions for stamping fees on bankers' acceptances and LIBOR loans and standby fees on unutilized credit lines that vary depending on certain consolidated financial ratios. As at December 31, 2010, approximately $0.8 billion was drawn under this facility.

As at December 31, 2010, the Company had $1.7 billion of senior unsecured notes outstanding as follows:

	Issue date	Amount (millions)	Term	Average interest rate	Weighted average remaining term
2007 Notes	May 31, 2007	US$475	8 – 15 years	5.80 percent	6.5 years
2008 Notes	May 29, 2008	US$480, CAD$30	8 – 12 years	6.25 percent	7.0 years
UK Notes	July 31, 2008	£57	10 years	6.95 percent (1)	7.6 years
2009 Notes	May 5, 2009	US$154, £20, €10, CAD$5	5 – 10 years	8.85 percent (2)	6.0 years
2010 Q1 Notes	March 16, 2010	US$250, CAD$50	5 – 15 years	5.47 percent	7.8 years
2010 Q4 Notes (3)	December 2, 2010	US$95, CAD$60	5 – 15 years	4.96 percent	9.8 years

(1) These notes bear interest at 7.78 percent in Pounds Sterling, however, contracts were entered to fix the interest rate at 6.95 percent in Canadian dollars and to fix the exchange rate on the repayment.
(2) The Company entered into contracts to fix the interest rate on the Pounds Sterling and Euro tranches, initially at 9.49 percent and 9.52 percent, to 9.15 percent and 9.22 percent, respectively.
(3) An additional US$75 million of proceeds were received in January 2011 which completed the private placement closing.

On March 16, 2010, the Company closed the private placement of the 2010 Q1 Notes with an aggregate principal amount of approximately US$250 million and CAD$50 million. The 2010 Q1 Notes had an original weighted average term of 8.6 years and bear a weighted average fixed interest rate of approximately 5.47 percent. The Company used the proceeds of the issue to repay advances on its syndicated bank facility.

In January 2011, the Company completed a closing of a private placement, the 2010 Q4 Notes, with an aggregate principal amount of approximately US$230 million. The 2010 Q4 Notes had an original weighted average term of 10.8 years and bear a weighted average fixed interest rate of approximately 5.00 percent. The Company used the proceeds of the issue to repay advances on its syndicated bank facility.

At December 31, 2010, the Company had the following interest rate swaps outstanding:

Effective date	Termination date	Initial term		Nominal amount (millions)	Fixed rate (percent)
December 2008	December 2011	3 years	$	500	1.61
January 2009	January 2014	5 years	$	600	2.71
June 2010	January 2014	3.5 years	$	50	1.94

The interest rates on any non-hedged portion of the Company's bank debt are subject to fluctuations in short-term money market rates as advances on the bank facility are generally made under short-term instruments. As at December 31, 2010, none (2009 – 14 percent) of our long-term debt instruments were exposed to changes in short-term interest rates. On December 31, 2010, our fixed interest rate debt (including the effects of interest rate swaps) had a weighted average rate of approximately 5.70 percent (2009 – 4.57 percent).

Financing charges for 2010 are higher year-over-year due to a higher percentage of our debt capital being held in senior unsecured notes compared to the prior period as well as the increased cost of borrowing with the new bank facility. The Company's senior unsecured notes contain higher interest rates than the syndicated bank facilities held in short-term money market instruments. Notwithstanding the current interest rate differentials, we believe the long-term and fixed interest rates inherent in the senior notes is favourable for a portion of our debt capital structure.

Realized gains and losses on the interest rate swaps are recorded as financing costs. For 2010 an expense of $21 million (2009 – $21 million and 2008 – nil) was recognized in financing expense to reflect that the floating interest rate was lower than the fixed interest rate transacted under our financial instruments.

Unit-Based Compensation

Unit-based compensation expense is related to our Trust Unit Rights Incentive Plan ("TURIP") and our Long-Term Retention and Incentive Plan ("LTRIP") as described in Note 13 to our audited consolidated financial statements. The LTRIP was implemented in the first quarter of 2010. Compensation expense related to the TURIP is based on the fair value of trust unit rights issued, determined using a Binomial Lattice option-pricing model. The fair value of TURIP rights issued is amortized over the remaining vesting periods on a straight-line basis and is allocated to operating and general and administrative expense as applicable. The intrinsic cost of the LTRIP is charged to income based on our unit price at the end of each reporting period plus accumulated dividends or distributions multiplied by the number of LTRIP awards outstanding. The LTRIP obligation is accrued over the vesting period as service is completed by employees and is allocated to operating and general and administrative expense as applicable based on a graded vesting schedule. Subsequent increases and decreases in the underlying unit price will result in increases and decreases, respectively, to the underlying LTRIP obligation until settlement.

(millions)	Year ended December 31 2010	2009	2008
TURIP			
Operating expense	**$ 11**	$ 13	$ 11
General and administrative expense	**36**	39	34
LTRIP			
Operating expense	**4**	-	-
General and administrative expense	**4**	-	-
Unit-based compensation expense	**$ 55**	$ 52	$ 45

The unit price used in the LTRIP intrinsic cost calculation at December 31, 2010 was $23.84 (2009 and 2008 – N/A).

General and Administrative Expenses ("G&A")

(millions, except per boe amounts)	Year ended December 31 2010	2009	2008
Gross	**$ 203**	$ 189	$ 195
Per boe	**3.38**	2.93	2.81
Net (including unit-based compensation)	**181**	168	158
Per boe	**3.00**	2.59	2.29
Net (excluding unit-based compensation)	**141**	129	124
Per boe	**$ 2.34**	$ 1.99	$ 1.80

We increased our complement of technical staff and consolidated our employees into one building prior to our conversion to an E&P company which led to higher staff and building occupancy costs in 2010 compared to 2009. The increase in the cost per boe in 2010 was due to higher costs and lower production volumes during the year from net property dispositions.

For 2009, the increase in the net cost per boe compared to 2008 was primarily due to lower overhead recoveries from the reduced capital expenditure program during 2009 and lower production volumes.

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

(millions, except per boe amounts)	Year ended December 31 2010	2009	2008
Depletion of oil and natural gas assets	**$ 1,293**	$ 1,514	$ 1,556
Accretion of asset retirement obligation	**45**	42	38
Total DD&A	**$ 1,338**	$ 1,556	$ 1,594
DD&A expense per boe	**$ 22.27**	$ 24.04	$ 22.98

DD&A for 2010 decreased compared to the prior year as a result of the contribution of assets into the Peace River Oil Partnership and Cordova Joint Venture and lower production volumes due to net property dispositions.

During 2009, Penn West had F&D costs which were lower than the historical DD&A rate, however, property dispositions that were completed in 2009 led to an increase in the rate compared to 2008.

Taxes

	Year ended December 31		
(millions)	**2010**	2009	2008
Future income tax (recovery) expense	**$ (319)**	$ (378)	$ 135

The 2010 amount included a $177 million recovery related to corporate restructuring. The comparative figure in 2009 included a $168 million recovery related to unrealized risk management losses and a $65 million recovery related to income tax legislation enacted by the Government of Canada which reduced the provincial component of the Specified Investment Flow-Through ("SIFT") tax rate from 13 percent to 10 percent. The expense in 2008 included a tax charge of $198 million related to unrealized risk management gains in 2008.

Under the income trust structure which we operated in until December 31, 2010, the operating entities made interest and royalty payments to the Trust, which transferred taxable income to the Trust level, eliminating income subject to corporate income taxes in the operating entities. The Trust eliminated its taxable income, in part, by deducting distributions paid to its unitholders. Under the SIFT legislation, enacted in June 2007, and which became effective on January 1, 2011 distributions are no longer tax deductible by certain income trusts.

On January 1, 2011, we converted into a publicly-traded corporation. In 2011 and beyond, we are now subject to current and future income taxes at Canadian corporate rates. As the currently legislated SIFT rates are comparable to corporate tax rates, we do not anticipate our conversion to an E&P company to result in a significant adjustment to our existing future tax liability under Canadian GAAP.

We currently have a significant tax pool base. Based on current commodity prices and capital spending plans, we forecast we could use these pools to shelter our taxable income for an extended period.

Tax Pools

	As at December 31		
(millions)	**2010**	2009	2008
Undepreciated capital cost (UCC)	**$ 1,122**	$ 1,379	$ 1,394
Canadian oil and gas property expense (COGPE)	**1,564**	1,912	2,496
Canadian development expense (CDE)	**1,494**	1,141	1,243
Canadian exploration expense (CEE)	**305**	280	60
Non-capital losses	**2,481**	2,139	1,646
Other	**31**	16	18
Total	**$ 6,997**	$ 6,867	$ 6,857

Tax pool amounts exclude income deferred in operating partnerships of $920 million in 2010 (2009 - $931 million and 2008 - $885 million).

Foreign Exchange

	Year ended December 31		
(millions)	**2010**	2009	2008
Unrealized foreign exchange (gain) loss	**$ (82)**	$ (186)	$ 203

We record unrealized foreign exchange gains or losses to translate the U.S., UK and Euro notes and the related accrued interest to Canadian dollars using the exchange rates in effect on the balance sheet date. The gains during 2010 and 2009 were primarily due to the strengthening of the Canadian dollar relative to the US dollar. The loss in 2008 was due to a stronger US dollar compared to the prior year.

Funds Flow and Net Income (Loss)

	Year ended December 31		
	2010	2009	2008
Funds flow [1] (millions)	**$ 1,185**	$ 1,493	$ $2,537
Basic per unit	**2.68**	3.62	6.75
Diluted per unit	**2.65**	3.60	6.66
Net income (loss) (millions)	**226**	(144)	1,221
Basic per unit	**0.51**	(0.35)	3.25
Diluted per unit	**$ 0.50**	$ (0.35)	$ 3.22

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

Funds flow in 2010 was lower than 2009 primarily as a result of net property dispositions and lower realized risk management gains. The 2009 comparative figure also includes the monetization of foreign exchange contracts for a gain of $75 million. Net income for 2010 was higher than 2009 primarily due to higher oil and natural gas revenues and lower unrealized risk management losses.

The decline in funds flow realized in 2009 compared to 2008 was primarily the result of lower revenue due to lower commodity prices. The reduction in net income during 2009 from 2008 was the result of lower revenues resulting from lower commodity prices and unrealized risk management losses.

	Year ended December 31					
	2010		2009		2008	
	per boe	**%**	per boe	%	per boe	%
Oil and natural gas revenues [1]	**$ 50.46**	**100**	$ 50.67	100	$ 67.06	100
Royalties	**(9.07)**	**(18)**	(7.66)	(15)	(12.95)	(19)
Operating expenses [2]	**(15.71)**	**(31)**	(14.93)	(30)	(12.31)	(18)
Transportation	**(0.55)**	**(1)**	(0.52)	(1)	(0.49)	(1)
Net operating income	**25.13**	**50**	27.56	54	41.31	62
General and administrative expenses	**(2.34)**	**(5)**	(1.99)	(4)	(1.80)	(3)
Financing [3]	**(2.89)**	**(6)**	(2.49)	(5)	(2.94)	(4)
Funds flow	**19.90**	**39**	23.08	45	36.57	55
Unrealized foreign exchange gain (loss)	**1.36**	**3**	2.88	6	(2.92)	(5)
Unit-based compensation	**(0.92)**	**(2)**	(0.81)	(2)	(0.65)	(1)
Risk management activities [4]	**0.40**	**1**	(9.17)	(18)	9.53	14
Depletion, depreciation and accretion	**(22.27)**	**(44)**	(24.04)	(47)	(22.98)	(34)
Future income tax recovery (expense)	**5.30**	**10**	5.84	12	(1.95)	(3)
Net income (loss)	**$ 3.77**	**7**	$ (2.22)	(4)	$ 17.60	26

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Operating expenses include realized gains/ losses on electricity swaps.
(3) Financing expenses include realized losses on interest rate swaps.
(4) Risk management activities relate to unrealized gains and losses on derivative instruments.

Capital Expenditures

	Year ended December 31		
(millions)	**2010**	2009	2008
Land acquisition and retention	**$ 102**	$ 19	$ 128
Drilling and completions	**800**	286	529
Facilities and well equipping	**281**	336	407
Geological and geophysical	**10**	9	13
Corporate	**11**	38	18
Capital expenditures	**1,204**	688	1,095
Joint venture, carried capital	**(17)**	-	-
Capital expenditures, net	**$ 1,187**	$ 688	$ 1,095

Total expenditures

	Year ended December 31		
(millions)	**2010**	2009	2008
Capital expenditures	**$ 1,204**	$ 688	$ 1,095
Property dispositions, net	**(1,306)**	(369)	(50)
Business combinations	**139**	116	5,525
Total expenditures	**$ 37**	$ 435	$ 6,570

During 2010, we increased our capital spending compared to 2009 to take advantage of success at our light-oil resource plays and in preparation for our conversion to an E&P company. This resulted in an increase in drilling and completions expenditures year-over-year. Our focus throughout 2010 was to continue to advance the appraisal of our key light-oil plays in the Cardium, the Colorado, the Carbonates and Waskada.

For 2010, $89 million was capitalized (2009 - $26 million disposed and 2008 - $25 million capitalized) for additions to asset retirement obligations from our capital program and property acquisitions, net of property dispositions, and changes to our future cost estimates.

Drilling

	Year ended December 31			
	2010		2009	
	Gross	**Net**	Gross	Net
Oil	**351**	**245**	102	68
Natural gas	**53**	**38**	40	17
Dry	**3**	**2**	2	2
	407	**285**	144	87
Stratigraphic and service	**54**	**34**	11	7
Total	**461**	**319**	155	94
Success rate (1)		**99%**		98%

(1) Success rate is calculated excluding stratigraphic and service wells.

January 2010 Asset Swap

In the first quarter of 2010, we closed an Asset Exchange Agreement increasing our position in our light-oil resource plays at Pembina and Dodsland with total production of approximately 560 boe per day in exchange for certain interests in the Leitchville area with total production of approximately 3,500 boe per day. Additionally, we received net cash proceeds of approximately $434 million which was applied to our bank facility.

Peace River Oil Partnership

In the second quarter of 2010, we closed the transaction creating the Peace River Oil Partnership to develop oil resources in the Peace River area of northern Alberta. We contributed assets valued at $1.8 billion, retaining a 55 percent interest in the partnership and received approximately $817 million which included $312 million cash paid upon closing and $505 million committed to us to fund our share of future capital and operating expenses for the Peace River Oil Partnership. As a result, on approximately the first $1.0 billion of capital and operating costs to be incurred by the partnership, we will contribute approximately $56 million while maintaining our 55 percent interest in the partnership. In addition, we closed a private placement issuing approximately 23.5 million trust units to our partner for gross proceeds of $435 million ($424 million net).

Cordova Joint Venture

In the third quarter of 2010, we closed a joint venture agreement with a subsidiary of Mitsubishi Corporation ("Mitsubishi") to develop our shale gas assets in the Cordova Embayment and certain conventional gas assets at our Wildboy property in northeastern British Columbia. As a result of the arrangement, we sold a 50 percent interest in these assets to Mitsubishi in exchange for approximately $250 million of cash and approximately $205 million of future commitments. Mitsubishi will fund $600 million of the first $800 million of capital expenditures in this joint venture and we will continue to serve as the operator of the assets.

Sifton Energy Inc. ("Sifton") acquisition

On December 22, 2010, we closed the acquisition of Sifton, a private oil and gas exploration company with assets primarily located in the Cardium light-oil resource play in Central Alberta. The total acquisition cost was approximately $108 million, which included the assumption of approximately $23 million of debt and working capital.

Reece Energy Exploration Corp ("Reece") Acquisition

On April 30, 2009, we closed the acquisition of Reece, an oil and gas exploration company. The acquisition was completed through a Plan of Arrangement wherein Reece shareholders received 0.125 of a Penn West trust unit for each Reece share. The total acquisition cost was approximately $101 million, which included the assumption of approximately $42 million of debt and working capital. The transaction added production of approximately 1,900 boe per day and 67,000 net acres of undeveloped land, the majority of which complements our Dodsland light-oil resource play in Southern Saskatchewan.

Goodwill

	Year ended December 31		
(millions)	**2010**	2009	2008
Balance, beginning of year	**$ 2,020**	$ 2,020	$ 652
Acquisitions	**-**	-	1,368
Balance, end of year	**$ 2,020**	$ 2,020	$ 2,020

We recorded goodwill on our acquisitions of Petrofund Energy Trust, Canetic Resources Trust and Vault Energy Trust. We determined there was no goodwill impairment at December 31, 2010.

Business Risks

The disclosures under this heading (excluding the information under environmental and climate change risk), in conjunction with Note 10 to the audited consolidated financial statements, are incorporated into and are an integral part of the audited consolidated financial statements.

We are exposed to normal market risks inherent in the oil and natural gas business, including, but not limited to, commodity price risk, foreign currency risk, credit risk, interest rate risk, liquidity risk and environmental and climate change risk. We seek to mitigate these risks through various business processes and management controls and from time to time by using financial instruments.

For a summary of outstanding financial instruments, please refer to “Financial Instruments” later in this MD&A and to Note 10 to our audited consolidated financial statements.

Commodity Price Risk

Commodity price fluctuations are among our most significant exposures. Crude oil prices are influenced by worldwide factors such as OPEC actions, world supply and demand fundamentals, and geopolitical events. Natural gas prices are influenced by the price of alternative fuel sources such as oil or coal and by North American natural gas supply and demand fundamentals including the levels of industrial activity, weather, storage levels and liquefied natural gas activity. In accordance with policies approved by our Board of Directors, we may, from time to time, manage these risks through the use of swaps, collars or other financial instruments up to a maximum of 50 percent of forecast sales volumes, net of royalties, for the balance of any current year plus one additional year forward and up to a maximum of 25 percent, net of royalties, for one additional year thereafter.

Foreign Currency Rate Risk

Prices received for crude oil are referenced to or denominated directly in US dollars, thus our realized oil prices are impacted by Canadian dollar to US dollar exchange rates. A portion of our debt capital is denominated in US dollars, thus the principal and interest payments in Canadian dollars are also impacted by exchange rates. When we consider it appropriate, we may use financial instruments to fix or collar future exchange rates to fix the Canadian dollar equivalent of crude oil revenues or to fix US denominated long-term debt principal repayments. At December 31, 2010, we had the following foreign currency forward contracts outstanding:

Initial Term	Nominal Amount (millions)	Termination date	Exchange rate
19-month term	Sell US$378	December 2011	1.06085 CAD/USD
8-year term	Buy US$80	May 2015	1.01027 CAD/USD
10-year term	Buy US$80	May 2017	1.00016 CAD/USD
12-year term	Buy US$70	May 2019	0.99124 CAD/USD
15-year term	Buy US$20	May 2022	0.98740 CAD/USD

At December 31, 2010, we had US dollar denominated debt with a face value of US$1.2 billion (2009 - US$0.9 billion) on which the repayment of the principal amount in Canadian dollars was not fixed.

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. Our accounts receivable are principally with customers in the oil and natural gas industry and are generally subject to normal industry credit risk, which includes the ability to recover unpaid receivables by retaining the partner's share of production when we are the operator. For oil and natural gas sales and financial derivatives, we follow a counterparty risk procedure whereby each counterparty is reviewed on a regular basis for the purpose of assigning a credit limit and may be requested to provide security if determined to be prudent. For financial derivatives, we normally transact with counterparties who are members of our banking syndicate or other counterparties that have investment grade bond ratings. We monitor credit events related to all counterparties and reassess credit exposures on a regular basis. As necessary, provisions for potential credit related losses are recognized.

As at December 31, 2010, the maximum exposure to credit risk was $386 million (2009 - $371 million) being the carrying value of the accounts receivable.

Interest Rate Risk

We currently maintain a portion of our debt capital in floating-rate bank facilities which results in exposure to fluctuations in short-term interest rates which remain at lower levels 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. As at December 31, 2010, none of our long-term debt instruments were exposed to changes in short-term interest rates (2009 – 14 percent).

As at December 31, 2010, we had a total of $1.7 billion of fixed interest rate debt instruments and $0.3 billion of convertible debentures outstanding. On the fixed interest rate debt the average remaining term was 7.2 years (2009 – 7.7 years) with an average interest rate of 5.7 percent (2009 – 4.6 percent), including the effects of interest rate swaps. For further details on these instruments, refer to the "Financing" and "Convertible Debentures" sections in this MD&A.

Liquidity Risk

Liquidity risk is the risk that we will be unable to meet our financial liabilities as they come due. Management utilizes short and long-term financial and capital forecasting programs to ensure credit facilities are sufficient relative to forecast debt levels, dividend and capital program levels are appropriate, and that financial covenants will be met. Management also regularly reviews capital markets to identify opportunities to optimize the debt capital structure on a cost effective basis. In the short term, liquidity is managed through daily cash management activities, short-term financing strategies and the use of collars and other financial instruments to increase the predictability of cash flow from operating activities. Additional information on specific instruments is discussed in Notes 7 and 8 to the audited consolidated financial statements.

The following table outlines estimated future contractual obligations for non-derivative financial liabilities as at December 31, 2010:

(millions)	**2011**	2012	2013	2014	2015	Thereafter
Bank debt	**$ -**	$ -	$ 773	$ -	$ -	$ -
Senior unsecured notes	**-**	-	5	60	251	1,407
Convertible debentures	**255**	-	-	-	-	-
Accounts payable	**743**	-	-	-	-	-
Distributions payable	**41**	-	-	-	-	-
Total	**$ 1,039**	$ -	$ 778	$ 60	$ 251	$ 1,407

Environmental and Climate Change Risk

The oil and gas industry has a number of environmental risks and hazards and is subject to regulation by all levels of government. Environmental legislation includes, but is not limited to, operational controls, site restoration requirements and restrictions on emissions of various substances produced in association with oil and natural gas operations. Compliance with such legislation could require additional expenditures and a failure to comply may result in fines and penalties which could, in the aggregate and under certain assumptions, become material.

We are dedicated to reducing the environmental impact from our operations through our environmental programs which include resource conservation, stakeholder communication, CO_2 sequestration, water management and site abandonment/reclamation. We continuously monitor our operations to minimize the environmental impact from our operations, allocate sufficient capital to reclamation and other activities and are committed to mitigating the impact in the areas in which we operate.

Liquidity and Capital Resources

Capitalization

	As at December 31					
	2010		2009		2008	
(millions)		**%**		%		%
Trust units issued, at market [1]	**$ 10,959**	**78**	$ 7,821	69	$ 5,245	54
Long-term debt	**2,496**	**18**	3,219	28	3,854	40
Convertible debentures – long term	**255**	**2**	255	2	289	3
Working capital deficiency [2]	**311**	**2**	106	1	270	3
Total enterprise value	**$ 14,021**	**100**	$ 11,401	100	$ 9,658	100

(1) The unit price at December 31, 2010 was $23.84 (2009 - $18.55 and 2008 - $13.57).
(2) Excludes the current portion of risk management, future income taxes and convertible debentures.

During 2010, we paid total distributions of $708 million (2009 – $910 million and 2008 – $1,500 million) including amounts funded by the distribution reinvestment plan. In preparation for our conversion to an E&P company, we reduced our distribution level to $0.09 per unit, per month during 2010.

The decline in long-term debt in 2010 was mainly due to repayments made on our syndicated bank facility using proceeds received from the January 2010 asset swap, cash received upon closing of the Peace River Oil Partnership transaction and the Cordova Joint Venture and an equity offering completed in June 2010 to a private investor. On April 30, 2010, the Company closed the renewal of its unsecured, revolving, syndicated bank facilities with an aggregate borrowing limit of $2.25 billion and as of December 31, 2010 had approximately $1.5 billion of unused credit capacity available. For further details on these debt instruments, please refer to the “Financing” and “Convertible Debentures” sections of this MD&A.

We actively manage our debt portfolio and consider opportunities to reduce or diversify our debt structure. We have an active risk management program to limit our exposure to certain risks and maintain close relationships with our lenders and agents to monitor credit market developments. These actions aim to increase the likelihood of maintaining our financial flexibility to capture opportunities available in the markets in addition to the continuation of our capital and dividend programs and the longer-term execution of our business strategies.

The Company has a number of covenants related to its syndicated bank facility and senior, unsecured notes. On December 31, 2010, the Company was in compliance with all of these financial covenants which comprise the following:

	Limit	December 31, 2010
Senior debt to EBITDA	Less than 3:1	**1.84**
Total debt to EBITDA	Less than 4:1	**1.86**
Senior debt to capitalization	Less than 50 percent	**23%**
Total debt [(1)] to capitalization	Less than 55 percent	**23-25%**

(1) The definitions of Total debt differ slightly among the agreements in relation to convertible debentures.

As at December 31, 2010, all senior, unsecured notes, except for the 2007 Notes, contain change of control provisions whereby if a change of control occurs, the Company may be required to offer to prepay the notes, which the holders have the right to refuse. Our conversion to a corporation did not trigger a change in control under the note agreements. As of January 1, 2011, upon completion of our corporate conversion, all note agreements now have change of control provisions.

As an income trust, we paid distributions in cash as the Trust was required to make distributions to unitholders in amounts at least equal to its taxable income; however, the amount of taxable income allocated to the Trust from the operating entities was subject to management's discretion. Beginning on January 1, 2011, under our new corporate structure, the amount of future cash dividends may vary depending on a variety of factors and conditions which can include fluctuations in commodity markets, production levels and capital expenditure requirements. Our dividend level could change based on these and other factors and is subject to the discretion of our Board of Directors.

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 obligations.

Convertible Debentures

During 2010, $18 million of convertible debentures matured and were settled in units (2009 – $7 million), none were redeemed and settled in units (2009 – $12 million) and none were redeemed and settled in cash (2009 – $4 million).

We have the option of settling the convertible debentures in cash or equity. At December 31, 2010, the balance of our unsecured, subordinated convertible debentures outstanding was as follows:

Description of security	Outstanding (millions)	Maturity date	Conversion price (per unit)	Redemption prices (per $1,000 face value)
PWT.DB.E 7.2% Convertible	$ 26	May 31, 2011	$ 75.00	$1,025 May 31, 2010 to maturity
PWT.DB.F 6.5% Convertible extendible	229	Dec. 31, 2011	$ 51.55	$1,025 Dec. 31, 2010 to maturity
Total	**$ 255**			

Standardized Distributable Cash

(millions, except per unit amounts)	Year ended December 31 2010	2009	2008
Cash flow from operating activities	**$ 1,217**	$ 1,401	$ 2,256
Productive capacity maintenance (1)	**(1,187)**	(688)	(1,095)
Standardized distributable cash	**30**	713	1,161
Proceeds from the issue of trust units (2)	**676**	393	246
Debt and working capital changes	**(20)**	(265)	143
Cash distributions declared	**$ 686**	$ 841	$ 1,550
Accumulated cash distributions, beginning	**4,501**	3,660	2,110
Accumulated cash distributions, ending	**$ 5,187**	$ 4,501	$ 3,660
Standardized distributable cash per unit, basic	**0.07**	1.73	3.09
Standardized distributable cash per unit, diluted	**0.07**	1.72	3.03
Standardized distributable cash payout ratio (3)	**22.87**	1.18	1.34
Distributions declared per unit	**$ 1.56**	$ 2.04	$ 4.08
Net income as a percentage of cash distributions declared	**33%**	N/A	79%
Cash flows from operating activities as a percentage of cash distributions declared	**177%**	167%	146%

(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, the Employee Retirement Savings Plan and equity issuances completed in February 2009 and June 2010.
(3) Represents cash distributions declared divided by standardized distributable cash.

(millions, except ratios)	To December 31, 2010
Cumulative standardized distributable cash from operations (1)	$ 3,467
Issue of trust units	1,605
Debt and working capital changes	115
Cumulative cash distributions declared (1)	$ 5,187
Standardized distributable cash payout ratio (2)	1.50

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

Productive capacity maintenance is the estimated amount of capital funds required in a period for an enterprise to maintain future cash flows 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.

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 reduction 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. 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.

Financial Instruments

We had the following financial instruments outstanding as at December 31, 2010. Fair values are determined using external counterparty information which is compared to observable market data. We limit our credit risk by executing counterparty risk procedures which include transacting only with institutions within our credit facility or with high credit ratings and by obtaining financial security in certain circumstances.

	Notional volume	Remaining term	Pricing	Fair value
Crude oil				
WTI Collars	35,000 bbls/d	Jan/11 – Dec/11	US$80.06 to $91.98/bbl	$ (70)
WTI Collars	15,000 bbls/d	Jan/12 – Dec/12	US$83.67 to $96.32/bbl	(17)
Electricity swaps				
Alberta Power Pool	90 MW	Jan/11 – Dec/11	$63.16/MWh	(10)
Alberta Power Pool	45 MW	Jan/12 – Dec/12	$53.02/MWh	(2)
Alberta Power Pool	30 MW	Jan/12 – Dec/13	$54.60/MWh	(1)
Alberta Power Pool	20 MW	Jan/13 – Dec/13	$56.10/MWh	-
Alberta Power Pool	50 MW	Jan/14 – Dec/14	$58.50/MWh	(2)
Interest rate swaps				
	$500	Jan/11 – Dec/11	1.61%	(1)
	$600	Jan/11 – Jan/14	2.71%	(13)
	$50	Jan/11 – Jan/14	1.94%	-
Foreign exchange forwards				
19-month term	US$378	Jan/11 – Dec/11	1.06085 CAD/USD	23
8-year term	US$80	2015	1.01027 CAD/USD	1
10-year term	US$80	2017	1.00016 CAD/USD	1
12-year term	US$70	2019	0.99124 CAD/USD	1
15-year term	US$20	2022	0.98740 CAD/USD	-
Cross currency swaps				
10-year term	£57	2018	2.0075 CAD/GBP, 6.95%	(28)
10-year term	£20	2019	1.8051 CAD/GBP, 9.15%	(6)
10-year term	€10	2019	1.5870 CAD/EUR, 9.22%	(2)
Total				$ (126)

Please refer to our website at www.pennwest.com for details of all financial instruments currently outstanding.

In 2011, we entered into crude oil collars for 6,000 barrels per day for the period of March 2011 to December 2011 at US$79.50 per barrel to US$122.13 per barrel and on 10,000 barrels per day for 2012 at US$85.50 per barrel to US$115.56 per barrel. Additionally in 2011, Penn West entered into foreign exchange forward contracts to fix approximately $128 million of future US denominated senior, unsecured note repayments at an exchange rate of 1.0150 CAD/USD.

Outlook

This outlook section is included to provide shareholders with information about our expectations as at March 17, 2011 for production and capital expenditures for 2011 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".

Based on an average crude oil price of WTI US$80.00 per barrel and an average natural gas price of $4.70 per mcf, we expect our 2011 exploration and development capital program to be in the range of approximately $1.1-$1.2 billion. We are focusing our 2011 capital program on our suite of large-scale light-oil plays including the Cardium, the Colorado, the Carbonates and Waskada. Based on this level of capital expenditures, we continue to forecast 2011 average production to be approximately 172,000 to 177,000 boe per day.

There have been no changes from our prior forecast for 2011 released on February 17, 2011 with our 2010 fourth quarter results and filed on SEDAR at www.sedar.com.

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on reported financial results for the 12 months subsequent to this reporting period, including risk management contracts entered to date, are based on forecasted results as discussed in the Outlook above.

			Impact on funds flow	
Change of:		Change	$ millions	$/share
Price per barrel of liquids	$	1.00	19	0.04
Liquids production		1,000 bbls/day	17	0.04
Price per mcf of natural gas	$	0.10	12	0.03
Natural gas production		10 mmcf/day	7	0.01
Effective interest rate		1%	4	0.01
Exchange rate ($US per $CAD)	$	0.01	21	0.05

Contractual Obligations and Commitments

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

(millions)	**2011**	2012	2013	2014	2015	Thereafter
Long-term debt	**$ -**	$ -	$ 778	$ 60	$ 251	$ 1,407
Transportation	**26**	15	14	9	5	-
Transportation ($US)	**4**	4	4	4	4	-
Power infrastructure	**30**	10	10	10	10	14
Drilling rigs	**9**	5	3	1	-	-
Purchase obligations (1)	**13**	13	13	11	10	8
Interest obligations	**154**	138	119	106	96	270
Office lease (2)	**71**	68	66	61	60	539
Asset retirement obligations (3)	**$ 65**	$ 62	$ 59	$ 57	$ 54	$ 356

(1) These amounts represent estimated commitments of $51 million for CO_2 purchases and $17 million for processing fees related to interests in the Weyburn Unit.
(2) Future office lease commitments will be reduced by sublease recoveries totalling $413 million.
(3) These amounts represent the inflated, discounted future reclamation and abandonment costs that are expected to be incurred over the life of the properties.

Our syndicated credit facility is due for renewal on April 30, 2013. If we are not successful in renewing or replacing the facility, we could be required to repay all amounts then outstanding on the facility or enter other loans including term bank loans. In addition, we have an aggregate of $1.7 billion in senior notes maturing between 2014 and 2025. We continuously monitor our credit metrics and maintain positive working relationships with our lenders, investors and agents.

Convertible debentures with an aggregate principal amount of $255 million were outstanding on December 31, 2010 (2009 - $273 million). A significant portion of the interest payable on convertible debentures may, at our option, be settled by the issuance of shares. As at March 17, 2011, convertible debentures with an aggregate principal amount of $249 million were outstanding. For a schedule of convertible debenture maturities, please refer to the “Convertible Debentures” section of this MD&A or Note 8 to the audited consolidated financial statements.

Equity Instruments

Trust units issued:	
Trust units as at December 31, 2010	459,682,249
Trust units cancelled on January 1, 2011	(459,682,249)
As at January 1, 2011	-
Common shares issued:	
Issuance of common shares on January 1, 2011	459,682,249
Issued on exercise of options	3,114,236
Issued on exercise of common share rights	330,920
Issued on settlement of restricted rights	8,848
Issued pursuant to dividend reinvestment plan	299,097
As at March 17, 2011	463,435,350

Trust unit rights outstanding:	
Trust unit rights outstanding as at December 31, 2010	31,365,478
Trust unit rights cancelled on January 1, 2011	(31,365,478)
As at January 1, 2011	-
Options outstanding:	
Issuance on January 1, 2011	27,586,712
Granted	6,587,773
Exercised	(3,114,236)
Forfeited	(187,245)
As at March 17, 2011	30,873,004
Common share rights outstanding:	
Issuance on January 1, 2011	3,778,766
Exercised	(330,920)
Forfeited	(50,851)
As at March 17, 2011	3,396,995

On January 1, 2011, we completed the previously announced Plan of Arrangement which resulted in our conversion to a publicly traded E&P company. Based on the Plan of Arrangement trust units were exchanged for common shares on a one-to-one basis. Additionally, as a result of the conversion the TURIP was amended and electing holders of trust unit rights received an option and a restricted right; those not electing received a common share right. These instruments were issued under our Stock Option Plan and our Common Share Rights Incentive Plan; please refer to our Information Circular and Proxy Statement dated November 10, 2010 related to our corporate conversion for more information.

Fourth Quarter 2010 Highlights

Key financial and operational results for the fourth quarter 2010 were as follows:

	Three months ended December 31		
	2010	2009	% change
Financial			
(millions, except per unit amounts)			
Gross revenues [1]	**$ 782**	$ 831	(6)
Funds flow	**305**	366	(17)
Basic per unit	**0.67**	0.87	(23)
Diluted per unit	**0.66**	0.86	(23)
Net loss	**(21)**	(12)	75
Basic per unit	**(0.05)**	(0.03)	67
Diluted per unit	**(0.05)**	(0.03)	67
Distributions paid [2]	**123**	189	(35)
Capital expenditures, net	**$ 400**	$ 196	100
Operations			
Daily production			
Light oil and NGL (bbls/d)	**88,447**	77,627	14
Heavy oil (bbls/d)	**16,849**	24,009	(30)
Natural gas (mmcf/d)	**365**	411	(11)
Total production (boe/d)	**166,148**	170,164	(2)
Average sales price			
Light oil and NGL (per bbl)	**$ 71.05**	$ 69.49	2
Heavy oil (per bbl)	**61.87**	62.97	(2)
Natural gas (per mcf)	**$ 3.79**	$ 4.39	(14)
Netback per boe			
Sales price	**$ 52.43**	$ 51.19	2
Risk management gain (loss)	**(1.51)**	1.89	(100)
Net sales price	**50.92**	53.08	(4)
Royalties	**(9.14)**	(9.35)	(2)
Operating expenses	**(15.92)**	(15.10)	5
Transportation	**(0.52)**	(0.52)	-
Netback	**$ 25.34**	$ 28.11	(10)

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

Financial

Gross revenues were lower in the fourth quarter of 2010 compared to 2009 primarily due to lower realized risk management gains in the period. This also resulted in a reduction of funds flow in the fourth quarter of 2010 compared to 2009.

The increase in net loss from the prior period was primarily due to a lower future income tax recovery in 2010 in comparison to 2009.

During the fourth quarter of 2010, we increased our capital spending recognizing successful results to-date at our light-oil resource plays and in advance of our conversion to an E&P company. For the fourth quarter of 2010, we drilled 116 net wells (2009 – 25) which included 93 net oil wells, 13 net natural gas wells and 10 net stratigraphic and service wells. The majority of these wells drilled in 2010 were horizontal multi-stage fracture wells located in our key light-oil resource plays.

Operations

Production was 166,148 boe per day in the fourth quarter of 2010. Our light-oil production volumes increased in the fourth quarter of 2010 compared to 2009, due to our concentrated capital program on our key light-oil resource plays. Exit production at December 31, 2010 was approximately 167,100 boe per day. Apportionment issues on certain Enbridge pipelines reduced year-end exit production by approximately 1,900 boe per day.

WTI crude oil prices averaged US$85.18 per barrel in the fourth quarter of 2010, an increase from WTI US$76.21 per barrel in the third quarter of 2010 and WTI US$76.17 per barrel in the fourth quarter of 2009. During the fourth quarter of 2010, the AECO Monthly Index averaged $3.58 per mcf compared to $3.72 per mcf in the third quarter of 2010 and $4.23 per mcf in the fourth quarter of 2009.

Netbacks were $25.34 per boe compared to $28.11 per boe in the fourth quarter of 2009. The decline was primarily due to realized risk management losses.

Disclosure Controls and Procedures

As of December 31, 2010, an internal evaluation was carried out under the supervision of our Chief Executive Officer (the "CEO") and Executive Vice President and Chief Financial Officer (the "CFO") of the effectiveness of Penn West's disclosure controls and procedures as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 (the "Exchange Act") and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the CEO and the CFO concluded that as of December 31, 2010 the disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed in the reports that Penn West files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by Penn West in the reports that it files or submits under the Exchange Act or under Canadian securities legislation is accumulated and communicated to the Trust's management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

Internal Control over Financial Reporting ("ICOFR")

We have a team of qualified and experienced staff who continue to maintain our compliance with the applicable regulations regarding internal control over financial reporting ("ICOFR"). We became a registrant under the U.S. Securities Exchange Act of 1934 and listed our trust units on the New York Stock Exchange in June 2006. As of December 31, 2010, an internal evaluation was carried out under the supervision of our CEO and CFO of the effectiveness of our ICOFR as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, the CEO and the CFO concluded that as of December 31, 2010 our ICOFR was effective. We have certified our ICOFR and obtained auditor attestation of the operating effectiveness of our internal control over financial reporting in conjunction with our 2010 year-end audited consolidated financial statements. All significant financial reporting processes have been documented, assessed, and tested. No changes in our ICOFR were made during the quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our ICOFR.

Future Accounting Pronouncements

Implementation of International Financial Reporting Standards

In January 2006, the Canadian Accounting Standards Board (the "AcSB") announced its decision to replace Canadian GAAP with International Financial Reporting Standards ("IFRS") for all Canadian Publicly Accountable Enterprises ("PAEs"), including Penn West. On February 13, 2008, the AcSB confirmed January 1, 2011 as the changeover date for PAEs to commence reporting under IFRS. Although IFRS is principles-based and uses a conceptual framework similar to Canadian GAAP, there are significant differences and choices in accounting policies, as well as increased disclosure requirements under IFRS.

IFRS 1 – Oil and Gas Exemption

In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1 "First-time adoption of IFRS" allowing additional exemptions for first-time adopters. Under these amendments, full cost oil and natural gas companies can elect to use the recorded amount under a previous GAAP as the deemed cost for oil and gas assets on the transition date to IFRS. We have elected to utilize this exemption.

Project Status

In 2008, we began our IFRS conversion project and assembled a project team and steering committee to ensure successful implementation within the required timeframe. Members selected for this team have expertise in a number of areas including; accounting, financial reporting, information technology, internal controls, investor relations, project management, taxation and treasury. These members and other finance and operational staff and members of our Board of Directors have received ongoing training related to IFRS. The project team and steering committee provide updates to senior management and the Audit Committee on a regular basis. Our changeover project consists of three main phases:

Diagnostic phase – This phase involved the identification of key differences between Canadian GAAP and IFRS. This phase began in 2008 and was completed in 2009.

Design and implementation phase – This phase has focused on accounting policy decisions and modifications to IT systems and accounting processes. As decisions are made during this phase we have and will continue to review our internal controls over financial reporting and disclosure controls and procedures and make modifications as required. We started this phase in 2009 and are currently close to completion.

Completion phase – This phase involves the final review of accounting policy choices, internal control changes, full implementation of IT processes and the conversion of financial statement balances and comparative figures to IFRS. We began this phase in early 2010 with the implementation of our IT process. Additionally, we advanced work on our January 1, 2010 transition date balance sheet during the fourth quarter of 2010. We will be continuing to work through this phase into 2011 prior to filing our first set of quarterly financial statements under IFRS being the first quarter of 2011, expected in early May 2011.

Fourth quarter of 2010 update – Throughout the fourth quarter we focused on advancing our work on our transition date balance sheet under IFRS. Any amendments to existing IFRS standards or implementation of new IFRS standards could lead to additional changes as we progress into 2011.

Significant Accounting Differences and Expected Accounting Policies

Component accounting – Under IFRS, depletion and depreciation of property, plant and equipment ("PP&E") will be based on significant components. We currently expect these components to consist of oil and natural gas assets, facilities, turnarounds and corporate assets.

Depletion and depreciation – Under Canadian GAAP, PP&E is generally depleted based on aggregations at the country level using the full cost method of accounting for oil and natural gas activities. Depletion of resource properties and facilities will generally continue to be calculated using the unit-of-production method; however, under IFRS there is an option to use production volumes before royalties on total proved reserves or total proved plus probable reserves. Depreciation of other assets can be calculated on a straight-line basis over their estimated useful life, rather than on a unit-of-production basis. We anticipate depleting our resource properties on a proved plus probable reserve basis using forecast prices.

Exploration and evaluation ("E&E") assets – O il and natural gas properties will be classified as either PP&E or E&E. Under Canadian GAAP, oil and gas assets are only classified as PP&E. E&E assets will consist of capital costs related to prospective assets for which the technical and commercial viability of extracting oil and natural gas has not yet been ascertained. These assets will initially be measured at cost and classified according to the nature of the associated expenditures.

E&E cost transfers – E&E costs will be reclassified to PP&E when proved reserves have been assigned to the asset, to the extent they are not impaired. If proved reserves will not be established through the completion of E&E activities and there are no future plans for development activity, then the E&E expenditures will be assessed for impairment. Any impairments will be charged to income.

Impairment of oil and natural gas properties – Under IFRS, impairment testing will be performed at a lower level than under current Canadian GAAP. As a consequence, impairment provisions are more likely to occur as properties will no longer be tested only at the country level. Under IFRS, impairments other than goodwill impairments may be reversed in the event future conditions change.

Trust unit rights classification – Under Canadian GAAP, trust unit rights are classified as equity instruments. Under IFRS, trust units carry a number of features that could result in either equity or liability treatment. Under IFRS "puttable financial instruments" with characteristics similar to ordinary shares are treated as equity instruments. We completed an analysis and concluded that our trust units receive equity classification.

Share-based payments – Under Canadian GAAP, share-based payments are classified as equity awards and are accordingly expensed using the straight-line method. Under IFRS, our equity awards meet the definition of a puttable financial instrument, thus the awards are considered a liability and expensed on a graded vesting schedule.

Asset retirement obligations ("ARO") or decommissioning provisions – Under Canadian GAAP, ARO is recorded if there is a legal obligation to abandon. Under IFRS, ARO is recorded if there is either a legal or constructive obligation to abandon.

ARO discounting – Discount rates used to calculate ARO are under review by our project team as there is currently diversity in practice when selecting a rate. As a result of using the deemed cost exemption, we are required to offset any changes to our ARO through retained earnings on the transition date. Under Canadian GAAP, we use a credit adjusted discount rate to calculate the obligation.

Future (deferred) income tax – Under Canadian GAAP, the rate used to calculate future income tax is based on a corporate average rate. Under IFRS, as a result of receiving a deduction for our distribution payments, the rate used in the future income tax calculation is based on the undistributed rate which is higher than the corporate rate.

January 1, 2010 Opening Balance Sheet Adjustments

E&E assets – We anticipate the reclassification of approximately $130 million of PP&E into E&E. Additionally, we anticipate recording approximately $50 million related to land currently considered non-prospective as a charge to retained earnings on January 1, 2010.

Impairment of oil and natural gas properties – On January 1, 2010, we expect no impairments to be recorded.

Share-based payments – In order to remove the equity treatment under Canadian GAAP and set-up the liability treatment under IFRS, we anticipate the removal of contributed surplus amounts related to stock-based compensation under Canadian GAAP of $123 million and the recognition of a unit rights liability under IFRS of approximately $70 million.

ARO – In our transition date balance sheet, we expect to record an additional provision as a result of the constructive obligations related to our pipelines. This additional provision will vary depending on the discount rate used. Additionally, a reduction from the credit-adjusted discount rate used to calculate ARO could lead to a material increase in the recorded asset retirement obligation in our transition date balance sheet.

Future (deferred) income tax – On January 1, 2010, we anticipate an increase in our future income tax liability by approximately $410 million with an offsetting charge to retained earnings due to the requirement to record future income taxes at the rate applicable to undistributed income on future income tax assets and liabilities at the income trust level. As we paid distributions throughout 2010 and upon conversion to a corporation on January 1, 2011, we expect that this charge will be reversed. Future income taxes under IFRS will also be adjusted for any changes to the recorded ARO, and other changes to the January 1, 2010 Opening Balance Sheet.

Current IASB Projects

The IASB currently has two projects in exposure draft form which could affect our reported financial position. The first relates to “Joint Arrangements” which outlines the appropriate accounting for joint operations, joint assets and joint ventures. Depending on the criteria, joint arrangements could be subject to either proportionate consolidation or equity accounting. This could affect the accounting for our interest in the Peace River Oil Partnership which is currently proportionately consolidated under Canadian GAAP. The standard is expected to be finalized in 2011. Additionally, in August 2010 the IASB and FASB issued an exposure draft related to “Leases” which eliminates the concept of operating leases, thereby classifying many leases as finance leases. This would require a lessee to record both a “right-of-use” asset and an obligation based on the present value of future lease payments along with increased disclosure requirements. Currently, the target date for this standard is mid-2011 with the effective date to follow. We are currently determining the effect of these exposure drafts.

IFRS impacts related to our corporate conversion

Future Income Tax

Under Canadian GAAP, there are no material changes to our future income tax balances as a result of our conversion to a corporation.

Effective January 1, 2010, as an income trust under IFRS, we are required to measure future income tax assets and liabilities at the Trust level at a tax rate of 39 percent, representing the tax rate applicable to undistributed profits of the Trust in the Province of Alberta. Future income tax will be recorded on this basis from January 1, 2010 until our conversion to a corporation on January 1, 2011. Under IFRS, upon conversion to a corporation, the future income tax assets and liabilities will be re-measured at the applicable corporate income tax rate of approximately 25 percent. We anticipate this re-measurement will result in a reduction of recorded future income taxes of approximately $300 - $350 million during the first quarter of 2011.

Stock-Based Compensation

Under IFRS, the exchange of trust units for common shares generally results in a shift from the liability treatment of a stock-based compensation award to equity treatment as the common shares are not considered puttable financial instruments. The recorded liability for equity awards will be reclassified to equity.

Effective January 1, 2011, we amended our TURIP and implemented a Stock Option Plan whereby TURIP holders could have elected to receive an option (a “Restricted Option”) and a right (a “Restricted Right”) for outstanding “in-the-money” TURIP rights. TURIP right holders who made the election have the choice to settle the Restricted Right in cash or shares upon exercise. For those TURIP holders who chose not to make the election or for TURIP rights that were “out-of-the money” on January 1, 2011, holders received a common share right under the Common Share Rights Incentive Plan (the “CSRIP”), which replaced the TURIP.

Under IFRS, Restricted Options and options issued under the CSRIP will be measured at fair value on January 1, 2011, the date of issuance, and will receive equity treatment. The fair value will be amortized as compensation expense over the expected vesting period of the award based on a graded vesting schedule.

The Restricted Right will be accounted for as a liability as holders may elect to settle the right in cash. Compensation expense will be based on the fair value method. The Restricted Rights will be expensed over the remaining life based on a graded vesting schedule.

Related-Party Transactions

During 2010, we incurred $2 million (2009 – $2 million) of legal fees from 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 under Canadian GAAP. In the determination of financial results, we must make certain critical 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.

All of our reserves were evaluated or audited by GLJ Petroleum Consultants Ltd. (”GLJ”) and Sproule Associates Limited (“SAL”), both independent engineering firms. Our reserves are 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, reservoir, 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, 2010.

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 income, included in DD&A. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the recorded 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 9 to the audited consolidated financial statements details the impact of these accounting standards.

Financial Instruments

Financial instruments included in the balance sheets consist of accounts receivable, fair values of derivative financial instruments, current liabilities, convertible debentures and long-term debt. Except for the senior notes and the convertible debentures, 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 applicable to the bank debt. The estimated fair value of the senior notes and the convertible debentures is disclosed in Notes 7 and 8 to the audited consolidated financial statements.

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, collars or other financial instruments may be utilized from time to time. 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.

Substantially 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 executing counterparty risk procedures which include transacting only with financial institutions who are members of our credit facility or those with high bond ratings as well as obtaining security in certain circumstances.

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. The goodwill impairment test consists of two parts. Under part 1, if the fair value of the reporting entity is less than its book value, part 2 of the test must be performed. The part 2 test compares the implied fair value of the goodwill to its carrying amount; if the carrying amount of goodwill exceeds the implied fair value an impairment loss is recorded. Penn West determined there was no goodwill impairment at December 31, 2010.

Future Income Tax

Future income taxes are recorded based on the asset and liability method of accounting whereby temporary differences are calculated assuming financial assets and liabilities will be settled at their carrying amount. Future income taxes are computed on temporary differences using substantively enacted income tax rates expected to apply when future income tax assets and liabilities are realized or settled.

Forward-Looking Statements

In the interest of providing our securityholders and potential investors with information regarding the Company, including management's assessment of our 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", "objective", "aim", "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: our belief that the earthquake and subsequent tsunami in Japan could impact energy markets, including a near term increase in demand for LNG and refined products, a near term decrease in demand for crude oil, and a long term increase in demand for all energy products; our belief that the delays that certain Canadian producers (including us) experienced in the second half of 2010 delivering certain of their production to market due to pipeline failures that occurred on the Enbridge system and resulting pipeline capacity issues will be resolved in the upcoming months; our anticipation that moving forward our shareholders will experience a level of return that includes an element of both growth and yield; the identification of over 8,000 drilling locations on our existing lands, including approximately 3,800 specific locations; the ability of our business strategies to enable a significant increase in our operating activities; our intention to allocate approximately 90 percent of our 2011 capital program to our light-oil projects; our intention to continuously evaluate the results of our 2011 capital program and assess areas where the rate of development may be economically increased; the ability of the Peace River Oil Partnership and the Cordova Joint Venture to allow us to assess the resource potential of the relevant assets and move into full-scale development of such assets in a shorter time-frame than we previously anticipated; our ability to execute on our corporate strategy of providing shareholders with a return including both growth and yield; our intention to redeploy funds not distributed to shareholders as a result of our most recent distribution decrease to advance the development of our resource plays; our objective to maintain a strategic mix of liquids and natural gas production in order to reduce exposure to price volatility that can effect a single commodity; our forecast that based on current commodity prices and capital spending plans, we could use our tax pools to shelter our taxable income for an extended period; the identity of our primary business risks going forward and the nature and effectiveness of our risk management strategies relating thereto, as more particularly described under "Business Risks"; the ability of our debt portfolio management program and our risk management program to increase the likelihood that we can maintain our financial flexibility to capture opportunities available in the markets in addition to the continuation of our capital and dividend programs and the longer-term execution of our business strategies; the factors that may affect the amount of future cash dividends that we pay; our belief that our environmental programs will be sufficient to meet or exceed existing environmental regulations and best industry practices; our belief that our only significant long-term unfunded contractual obligation at this time is for asset retirement obligations; our belief that our current environmental programs will be sufficient to fund our asset retirement obligations over the life of our reserves; the disclosure set out under the heading "Outlook", which sets forth management's expectations as to our exploration and development capital expenditure levels for 2011, the identity of the light-oil plays on which the 2011 capital program will focus, and our forecast average daily production for 2011; the disclosure contained under the heading "Sensitivity Analysis" relating to the estimated sensitivity to selected key assumptions of our reported financial results during 2011; and our identification of the significant accounting differences between our current accounting policies under Canadian GAAP and our expected accounting policies under IFRS and our expectations regarding the impact of those changes on our historical and future financial results and financial statements (including in relation to our corporate conversion).

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; drilling results; future exchange rates and interest rates; the amount of future cash dividends that we intend to pay; our ability to obtain equipment in a timely manner to carry out development activities and the costs thereof; 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, many of the forward-looking statements contained in this document are located proximate to assumptions that are specific to those forward-looking statements, and such assumptions should be taken into account when reading such forward-looking statements: see in particular the assumptions identified under the headings "Outlook" and "Sensitivity Analysis".

Although we believe 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 our 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: 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, including the completed acquisitions discussed herein; 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 and changes thereto; 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 dispositions, acquisitions, joint ventures and partnerships, including the completed dispositions, acquisitions, joint ventures and partnerships discussed herein; changes in tax and other laws that affect us and our securityholders; changes in government royalty frameworks; uncertainty of obtaining required approvals for acquisitions and mergers; the potential failure of counterparties to honour their contractual obligations; and the other factors described under "Business Risks" in this document and in our 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, we do 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 external 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.

/s/ William E. Andrew	/s/ Murray R. Nunns	/s/ Todd H. Takeyasu
William E. Andrew Chief Executive Officer	Murray R. Nunns President and COO	Todd H. Takeyasu Executive Vice President and CFO

March 17, 2011

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Penn West Petroleum Ltd. (formerly the Unitholders of Penn West Energy Trust)

We have audited the accompanying consolidated financial statements of Penn West Energy Trust and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, the consolidated statements of operations and retained earnings (deficit) and cash flows for the years then ended, and notes comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinions.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Penn West Energy Trust and its subsidiaries as at December 31, 2010 and 2009 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

/s/ KPMG LLP

Chartered Accountants
Calgary, Canada
March 17, 2011

Penn West Energy Trust
Consolidated Balance Sheets

(CAD millions)	As at December 31 2010	2009
Assets		
Current		
Accounts receivable (note 3)	**$ 386**	$ 371
Future income taxes (note 11)	**17**	37
Other (note 3)	**87**	101
	490	509
Deferred funding obligation (note 4)	**678**	-
Property, plant and equipment (note 5)	**10,180**	11,347
Goodwill (note 6)	**2,020**	2,020
	12,878	13,367
	$ 13,368	$ 13,876
Liabilities and unitholders' equity		
Current		
Accounts payable and accrued liabilities (note 3)	**$ 743**	$ 515
Distributions payable	**41**	63
Risk management (note 10)	**62**	130
	846	708
Long-term debt (note 7)	**2,496**	3,219
Convertible debentures (note 8)	**255**	273
Asset retirement obligations (note 9)	**653**	568
Risk management (note 10)	**64**	21
Future income taxes (note 11)	**855**	1,169
	5,169	5,958
Unitholders' equity		
Unitholders' capital (note 12) (Units outstanding 2010 – 459,682,249, 2009 – 421,638,737)	**9,177**	8,451
Contributed surplus (note 12)	**138**	123
Deficit	**(1,116)**	(656)
	8,199	7,918
	$ 13,368	$ 13,876

Contractual obligations and commitments (note 16)
Subsequent events (notes 7, 10 and 21)

See accompanying notes to the audited consolidated financial statements.

Approved on behalf of the Board of Directors of Penn West Petroleum Ltd.:

/s/ John A. Brussa
John A. Brussa
Chairman

/s/ James C. Smith
James C. Smith
Director

Penn West Energy Trust
Consolidated Statements of Operations and Retained Earnings (Deficit)

(CAD millions, except per unit amounts)	Years ended December 31 2010	2009
Revenues		
Oil and natural gas	**$ 3,054**	$ 2,859
Royalties	**(545)**	(495)
	2,509	2,364
Risk management gain (loss) (note 10)		
Realized	**(20)**	344
Unrealized	**23**	(554)
	2,512	2,154
Expenses		
Operating (note 13)	**959**	979
Transportation	**33**	34
General and administrative (note 13)	**181**	168
Financing (notes 7 and 8)	**174**	161
Depletion, depreciation and accretion	**1,338**	1,556
Unrealized risk management (gain) loss (note 10)	**(2)**	39
Unrealized foreign exchange gain	**(82)**	(186)
Transaction costs	**4**	-
Gain on currency contracts (note 10)	**-**	(75)
	2,605	2,676
Loss before taxes	**(93)**	(522)
Taxes		
Future income tax recovery (note 11)	**(319)**	(378)
Net and comprehensive income (loss)	**$ 226**	$ (144)
Retained earnings (deficit), beginning of year	**$ (656)**	$ 329
Distributions declared (note 14)	**(686)**	(841)
Deficit, end of year	**$ (1,116)**	$ (656)
Net income (loss) per unit (note 15)		
Basic	**$ 0.51**	$ (0.35)
Diluted	**$ 0.50**	$ (0.35)
Weighted average units outstanding (millions)		
Basic	**441.8**	412.9
Diluted	**447.6**	412.9

See accompanying notes to the audited consolidated financial statements.

Penn West Energy Trust
Consolidated Statements of Cash Flows

(CAD millions)	Years ended December 31 **2010**	2009
Operating activities		
Net income (loss)	**$ 226**	$ (144)
Depletion, depreciation and accretion (note 5)	**1,338**	1,556
Future income tax recovery (note 11)	**(319)**	(378)
Unit-based compensation (note 13)	**47**	52
Unrealized risk management (gain) loss (note 10)	**(25)**	593
Unrealized foreign exchange gain	**(82)**	(186)
Asset retirement expenditures	**(53)**	(65)
Change in non-cash working capital (note 17)	**85**	(27)
	1,217	1,401
Investing activities		
Additions to property, plant and equipment	**(1,187)**	(688)
Acquisitions of property, plant and equipment	**(637)**	(32)
Dispositions of property, plant and equipment	**1,148**	401
Change in non-cash working capital (note 17)	**155**	(79)
	(521)	(398)
Financing activities		
Decrease in bank loan	**(1,101)**	(687)
Proceeds from issuance of notes (note 7)	**460**	238
Issue of equity	**557**	280
Distributions paid	**(591)**	(799)
Redemption of convertible debentures	**-**	(4)
Repayment of acquired facilities (note 18)	**(21)**	(31)
	(696)	(1,003)
Change in cash	**-**	-
Cash, beginning of year	**-**	-
Cash, end of year	**$ -**	$ -
Interest paid	**$ 147**	$ 147
Income taxes recovered	**$ (1)**	$ (3)

See accompanying notes to the audited consolidated financial statements.

(All tabular amounts are in millions except numbers of units, per unit amounts, percentages and various figures in Note 10)

1. Structure of Penn West

On January 1, 2011, Penn West Energy Trust ("Penn West" or the "Trust") completed its plan of arrangement under which Penn West converted from an income trust to a corporation, Penn West Petroleum Ltd. (the "Company") which is operating under the trade name of Penn West Exploration. These consolidated financial statements are presented under Penn West's former structure, as an income trust, as at and for the years ended December 31, 2010 and 2009. For more information on the conversion to a corporation, refer to Note 21, Subsequent event.

As at December 31, 2010, Penn West was an open-ended, unincorporated investment trust governed by the laws of the Province of Alberta, Canada. The business of Penn West and the Company is to indirectly explore for, develop and hold interests in petroleum and natural gas properties through investments in securities of subsidiaries and, in the situation of the Trust, net profit interests in oil and natural gas properties. As at December 31, 2010 Penn West owned 100 percent of the equity, directly or indirectly, of the entities that carry on the oil and natural gas business of Penn West, except for an unincorporated joint venture arrangement (the "Peace River Oil Partnership") in which Penn West's wholly owned subsidiaries hold a 55 percent interest. The activities of these entities, with the exception of the Peace River Oil Partnership, were financed through interest-bearing notes from Penn West and third-party debt as described in Notes 7 and 8. The business activities of the Company are expected to be substantively the same as those of the Trust.

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

Under the terms of its trust indenture applicable while an income trust, Penn West was 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.

2. Significant accounting policies

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

a) Principles of consolidation

These consolidated financial statements include the accounts of Penn West and its wholly owned subsidiaries and partnerships. Results from acquisitions are included in Penn West's reported results from the date of close.

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 20 percent or more 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 or audited 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. Total depletable costs include estimated future costs to be incurred in developing proved reserves and exclude estimated equipment salvage values and the lower of cost and market value 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 carrying cost of unproved properties. Expected future cash flows are discounted at Penn West's estimated risk free rate.

iv) Asset retirement obligations

The fair value of legal obligations for property abandonment and site restoration are 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 (except for significant natural gas processing facilities).

d) Joint operations

A significant portion of Penn West's exploration and development activities are conducted jointly with others. The accounts reflect only Penn West's proportionate interest in such activities.

Penn West entered into the Peace River Oil Partnership during the second quarter of 2010. This arrangement is accounted for using the proportionate consolidation method with Penn West recognizing its 55 percent share of revenues, expenses, assets and liabilities. Please refer to Note 4 below.

e) 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 which of the following categories the financial instrument has been classified: held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial instruments.

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 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 income; and held to maturity financial assets, loans and receivables and other financial liabilities are measured at amortized cost. Penn West currently has no items requiring separate disclosure as OCI.

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 receivables are designated as loans and receivables. Accounts payable and accrued liabilities, distributions payable, convertible debentures and long-term debt are designated as other financial liabilities. All risk management assets and liabilities are derivative financial instruments designated 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 unit-of-production basis. Costs associated with the production of proprietary injectants are charged to income.

g) Foreign currency translation

Monetary items, such as accounts receivable 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 transactions occurred. Revenues and expenses denominated in foreign currencies are translated at the average exchange rate in effect during each period. Foreign exchange gains or losses on translation are included in income.

h) Unit-based compensation

Penn West has a Trust Unit Rights Incentive Plan ("TURIP"), as outlined in Note 13. Compensation expense for the plan is based on the fair value of rights granted, 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 when granted. Costs in respect of the Employee Retirement Savings Plan are expensed as incurred.

In the first quarter of 2010, Penn West implemented a Long-Term Retention and Incentive Plan as outlined in Note 13. Compensation expense for the plan is based on an intrinsic cost calculation on each balance sheet date using the awards outstanding and Penn West's unit price from the Toronto Stock Exchange. The awards are expensed over the vesting period based on a graded vesting schedule. Subsequent increases and decreases in the underlying unit price results in increases and decreases, respectively, to the accrued obligation until settlement. Adjustments to the accrued obligation are recorded in compensation expense during the period.

i) Revenue recognition

Revenues from the sale of crude oil, natural gas liquids and natural gas are recognized when title passes from the Company to purchasers.

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 substantively enacted income tax rates expected to apply when future income tax assets and liabilities are realized or settled. Penn West is taxable on income in excess of distributions and certain other deductions and expenses.

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 indicate impairment may have occurred. If impairment exists, the impairment amount is charged to income.

The impairment test consists of two steps. First, the fair value of Penn West is compared to the carrying amount, including goodwill, to identify a potential impairment. Fair value is determined using the market price of outstanding trust units on the balance sheet date. If the fair value is greater than the carrying amount, goodwill is considered not impaired and the second step is not required. 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 Penn West 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) Use of estimates

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, asset retirement obligations including the accretion thereof and future income taxes. 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. The measurement of the asset retirement obligation involves the use of estimates and assumptions including the discount rate, the expected life of the asset and/or field and the future abandonment costs. The calculation of future income taxes is based on a number of assumptions including estimating the future periods in which temporary differences, tax losses and other tax credits will reverse and the use of substantively enacted tax rates at the balance sheet date. These and other estimates are subject to measurement uncertainty and the effect on the financial statements of changes in these estimates could be material.

m) Transportation expense

Transportation relates to costs paid by Penn West for the shipping of natural gas, crude oil and NGLs from the wellhead to the point of title transfer. These costs are recognized as transportation is incurred.

n) Per unit calculations

Penn West follows the treasury stock method to compute the dilutive impact of equity instruments. 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.

Penn West follows the “if converted” method to compute the dilutive impact of the convertible debentures which assumes the outstanding debentures have been converted at the later of the beginning of the period or issuance.

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,
- the embedded instrument, if separated, meets the definition of a derivative,
- the hybrid contract is not measured at fair value or designated as held for trading.

Penn West 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 and 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. Penn West currently has no items requiring separate disclosure as OCI on a statement of Comprehensive Income.

q) Transaction costs

Transaction costs related to acquisitions and divestiture activities and financing transactions are charged to income.

r) Future Accounting Pronouncements

In January 2006, the Canadian Accounting Standards Board (the "AcSB") announced its decision to replace Canadian GAAP with International Financial Reporting Standards ("IFRS") for all Canadian Publicly Accountable Enterprises ("PAEs"), including Penn West. On February 13, 2008, the AcSB confirmed January 1, 2011 as the transition date for PAEs to commence reporting under IFRS. Although IFRS is principles-based and uses a conceptual framework similar to Canadian GAAP, there are significant differences and choices in accounting policies, as well as increased disclosure requirements under IFRS.

In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1 "First-time adoption of IFRS" providing exemptions for first-time adopters. Under these amendments, oil and gas companies can elect to use historical cost under a previous GAAP as the deemed cost for oil and gas assets on the transition date to IFRS.

3. Working capital components

	As at December 31	
	2010	2009
Components of accounts receivable		
Trade	**$ 70**	$ 93
Accruals	**316**	274
Other	**-**	4
	$ 386	$ 371
Components of other assets		
Prepaid expenses	**$ 66**	$ 70
Inventory	**21**	31
	$ 87	$ 101
Components of accounts payable and accrued liabilities		
Accounts payable	**$ 168**	$ 149
Royalty payable	**70**	77
Capital accrual	**285**	130
Operating accrual	**173**	123
Other	**47**	36
	$ 743	$ 515

4. Deferred funding obligation

Peace River Oil Partnership

On June 1, 2010, Penn West entered a partnership agreement to develop oil assets in the Peace River area in Alberta. Pursuant to the agreement, Penn West contributed assets with a fair value of $1.8 billion for a 55 percent interest in the partnership. Penn West received cash consideration of $312 million upon closing and received an additional $505 million in future commitments from Penn West's partner to fund its share of future capital and operating expenses in the Peace River Oil Partnership. As at December 31, 2010, approximately $473 million of deferred funding obligation remained.

Cordova Joint Venture

On September 23, 2010, Penn West entered into a joint venture agreement to develop its unconventional natural gas assets located in the Cordova Embayment and certain conventional assets located at its Wildboy play in northeastern British Columbia. Penn West sold a 50 percent interest in the assets for cash consideration of approximately $250 million upon closing and approximately $205 million in future commitments from Penn West's partner for its share of future capital costs in the joint venture. As at December 31, 2010, approximately $205 million of deferred funding remained.

5. Property, plant and equipment

	As at December 31	
	2010	2009
Oil and natural gas properties, including production and processing equipment	**$ 18,055**	$ 17,929
Accumulated depletion and depreciation	**(7,875)**	(6,582)
Net book value	**$ 10,180**	$ 11,347

In addition to Penn West's net share of capital overhead recoveries, capital additions included approximately $24 million of staff costs directly attributable to exploration and development activities (2009 – $nil).

In 2010, asset retirement obligations increased by $89 million (2009 - $26 million reduction) reflecting our capital program, net property acquisitions and changes to our future cost estimates. At December 31, 2010, unevaluated property excluded from the depletion base was $395 million (2009 - $393 million) based on the lower of net realizable value and cost, less any impairment. The depletion and depreciation calculation includes future capital costs to develop proved reserves of $1,389 million (2009 - $1,152 million).

An impairment test was performed on the costs capitalized to oil and natural gas properties at December 31, 2010 and 2009. On these dates, no impairment was calculated as 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 2010 impairment test:

	WTI ($US/ bbl)	AECO ($CAD/mcf)	Exchange rate ($US equals $1 CAD)
2011	$ 88.20	$ 4.10	0.96
2012	89.07	4.70	0.96
2013	89.38	5.15	0.96
2014	90.44	6.17	0.96
2015 – 2020	$ 97.56	$ 6.87	0.96
Thereafter (inflation percentage)	1.8%	1.8%	-

6. Goodwill

	Year ended December 31	
	2010	2009
Balance, beginning and end of year	**$ 2,020**	$ 2,020

Penn West recorded goodwill on its acquisitions of Petrofund Energy Trust, Canetic Resources Trust and Vault Energy Trust. Goodwill is subject to impairment testing on at least an annual basis. A goodwill impairment test was performed at December 31, 2010 and 2009 with no impairment noted.

7. Long-term debt

	As at December 31	
	2010	2009
Bankers' acceptances and prime rate loans	**$ 773**	$ 1,874
U.S. Senior unsecured notes – 2007 Notes		
5.68%, US$160 million, maturing May 31, 2015	**159**	168
5.80%, US$155 million, maturing May 31, 2017	**154**	163
5.90%, US$140 million, maturing May 31, 2019	**139**	147
6.05%, US$20 million, maturing May 31, 2022	**20**	21
	472	499
Senior unsecured notes – 2008 Notes		
6.12%, US$153 million, maturing May 29, 2016	**152**	160
6.16%, CAD$30 million, maturing May 29, 2018	**30**	30
6.30%, US$278 million, maturing May 29, 2018	**276**	292
6.40%, US$49 million, maturing May 29, 2020	**49**	52
	507	534
UK Senior unsecured notes – UK Notes		
6.95%, £57 million, maturing July 31, 2018 (1)	**88**	97
Senior unsecured notes – 2009 Notes		
8.29%, US$50 million, maturing May 5, 2014	**50**	52
8.89%, US$35 million, maturing May 5, 2016	**35**	36
9.32%, US$34 million, maturing May 5, 2019	**34**	36
8.89%, US$35 million, maturing May 5, 2019 (2)	**35**	37
9.15%, £20 million, maturing May 5, 2019 (3)	**31**	34
9.22%, €10 million, maturing May 5, 2019 (4)	**13**	15
7.58%, CAD$5 million, maturing May 5, 2014	**5**	5
	203	215
Senior unsecured notes – 2010 Q1 Notes		
4.53%, US$28 million, maturing March 16, 2015	**27**	-
4.88%, CAD$50 million, maturing March 16, 2015	**50**	-
5.29%, US$65 million, maturing March 16, 2017	**64**	-
5.85%, US$112 million, maturing March 16, 2020	**112**	-
5.95%, US$25 million, maturing March 16, 2022	**25**	-
6.10%, US$20 million, maturing March 16, 2025	**20**	-
	298	-
Senior unsecured notes – 2010 Q4 Notes		
4.44%, CAD$10 million, maturing December 2, 2015	**10**	-
4.17%, US$18 million, maturing December 2, 2017	**18**	-
5.38%, CAD$50 million, maturing December 2, 2020	**50**	-
4.88%, US$49 million, maturing December 2, 2020	**49**	-
4.98%, US$18 million, maturing December 2, 2022	**18**	-
5.23%, US$10 million, maturing December 2, 2025	**10**	-
	155	-
Total long-term debt	**$ 2,496**	$ 3,219

(1) These notes bear interest at 7.78 percent in Pounds Sterling, however, contracts were entered which fixed the interest rate at 6.95 percent in Canadian dollars.
(2) This portion of the 2009 Notes has equal repayments, beginning in 2013, over the remaining seven years.
(3) These notes bear interest at 9.49 percent in Pounds Sterling, however, contracts were entered into which fixed the interest rate at 9.15 percent in Canadian dollars.
(4) These notes bear interest at 9.52 percent in Euros, however, contracts were entered into which fixed the interest rate at 9.22 percent in Canadian dollars.

The Company has a three-year, unsecured, revolving syndicated bank facility with an aggregate borrowing limit of $2.25 billion. The facility expires on April 30, 2013 and is extendible. The credit facility contains provisions for stamping fees on bankers' acceptances and LIBOR loans and standby fees on unutilized credit lines that vary depending on certain consolidated financial ratios. In 2010, Penn West's weighted average interest rate under the syndicated bank facility was 2.4 percent (2009 – 1.1 percent). At December 31, 2010, the Company had approximately $1.5 billion of unused credit capacity available.

Letters of credit totalling $2 million were outstanding on December 31, 2010 (2009 - $2 million) that reduced the amount otherwise available to be drawn on the syndicated bank facility.

Financing costs, including interest expense on the syndicated bank facility, the senior unsecured notes and convertible debentures, were $174 million for 2010 (2009 - $161 million). Also included in financing costs are realized losses on interest rate swaps of $21 million for 2010 (2009 - $21 million).

On January 4, 2011, Penn West received the proceeds on the second tranche of its 2010 Q4 Notes for a total of approximately US$75 million. The aggregate principal of the 2010 Q4 Notes was approximately US$230 million.

The estimated fair value of the outstanding unsecured notes was as follows:

	As at December 31	
	2010	2009
2007 Notes	**$ 500**	$ 508
2008 Notes	**557**	558
UK Notes	**87**	99
2009 Notes	**239**	247
2010 Q1 Notes	**309**	-
2010 Q4 Notes	**151**	-
Total	**$ 1,843**	$ 1,412

8. Convertible debentures

Penn West's outstanding balances and estimated fair values for the unsecured, subordinated convertible debentures were as follows:

	As at December 31	
	2010	2009
Total	**$ 255**	$ 273
Total fair value (1)	**$ 262**	$ 277

(1) Based on quoted market value.

At December 31, 2010, Penn West had the following unsecured, subordinated convertible debentures outstanding classified as a liability. The equity component was insignificant. Penn West has the option of settling the convertible debentures in cash or equity.

Description of security	Symbol	Maturity date	Conversion price (per unit)	Redemption prices (per $1,000 face value)
7.2% Convertible	PWT.DB.E	May 31, 2011	$ 75.00	$1,025 May 31, 2010 to maturity
6.5% Convertible extendible	PWT.DB.F	Dec. 31, 2011	$ 51.55	$1,025 Dec. 31, 2010 to maturity

During 2010, $18 million of convertible debentures matured and were settled in units (2009 – $7 million), none were redeemed and settled in units (2009 – $12 million) and none were redeemed and settled in cash (2009 – $4 million).

	Balance, Dec. 31, 2008	Redeemed	Matured	Balance, Dec. 31, 2009	Matured	**Balance, Dec. 31, 2010**
PWT.DB.B – 8.0%	$ 7	$ -	$ (7)	$ -	$ -	**$ -**
PWT.DB.C – 8.0%	16	(16)	-	-	-	**-**
PWT.DB.D – 6.5%	18	-	-	18	(18)	**-**
PWT.DB.E – 7.2%	26	-	-	26	-	**26**
PWT.DB.F – 6.5%	229	-	-	229	-	**229**
Total	$ 296	$ (16)	$ (7)	$ 273	$ (18)	**$ 255**

9. Asset retirement obligations

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

At December 31, 2010, the total estimated amount to settle Penn West's asset retirement obligations on an uninflated and undiscounted basis was $2.6 billion (2009 - $2.4 billion) and on an inflated and undiscounted basis was $4.5 billion (2009 - $4.0 billion). The asset retirement obligation was determined by applying an inflation factor of 2.0 percent (2009 - 2.0 percent) and the inflated amount was discounted using a credit-adjusted rate of 7.0 percent (2009 - 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 22 years. Future cash flows from operating activities are expected to fund the obligations.

Changes to asset retirement obligations were as follows:

	Year ended December 31	
	2010	2009
Balance, beginning of year	**$ 568**	$ 614
Net liabilities incurred (disposed) during the year	**44**	(26)
Increase in liability due to change in estimate	**45**	-
Liabilities settled during the year	**(53)**	(65)
Liabilities acquired during the year	**4**	3
Accretion charges	**45**	42
Balance, end of year	**$ 653**	$ 568

10. Risk management

Financial instruments included in the balance sheets consist of accounts receivable, fair values of derivative financial instruments, current liabilities, convertible debentures and long-term debt. Except for the senior, unsecured notes described in Note 7 and the convertible debentures described in Note 8, 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 applicable to the bank facility.

A detailed discussion of the key business risks faced by Penn West, which include normal market risk inherent in the oil and natural gas business, commodity price risk, foreign currency rate risk, credit risk, interest rate risk and liquidity risk, is included in the Management's Discussion and Analysis for the year ended December 31, 2010 under the heading "Business Risks". The disclosure under that heading is hereby incorporated by reference into, and forms an integral part of, these financial statements.

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.

Crude oil sales are referenced to or denominated in US dollars. Crude oil prices realized in Canadian dollars are accordingly impacted directly by Canadian dollar to US dollar exchange rates. A portion of Penn West's long-term debt is denominated in US dollars, Pounds Sterling and Euros and is affected by foreign exchange fluctuations. From time to time, Penn West may use financial instruments to fix future foreign exchange rates.

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, foreign 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 primarily with counterparties that are members of our banking syndicate or that have investment grade ratings.

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

Penn West utilizes financial and capital forecasting programs to ensure credit facilities are sufficient relative to forecast debt levels, distribution and capital program levels are appropriate, and that financial covenants will be met. Penn West continuously monitors capital markets to identify opportunities to optimize its debt capital structure.

The fair values of all outstanding financial commodity, power, interest rate and foreign exchange contracts are reflected on the balance sheet with the changes during the period recorded in income as unrealized gains or losses.

As at December 31, 2010 and 2009, the only asset or liability measured at fair value on a recurring basis was the risk management asset and liability, which was valued based on quoted prices in markets that are not active or based on prices that are observable for the asset or liability ("Level 2 inputs").

The following table reconciles the changes in the fair value of financial instruments outstanding:

	Year ended December 31	
Risk management	**2010**	2009
Balance, beginning of year	**$ (151)**	$ 442
Unrealized gain (loss) on financial instruments:		
Commodity collars	**23**	(554)
Electricity swaps	**8**	(25)
Interest rate swaps	**(3)**	32
Foreign exchange forwards	**16**	(51)
Cross currency swaps	**(19)**	5
Fair value, end of year	**$ (126)**	$ (151)
Total fair value consists of the following:		
Fair value, end of year – current portion	**$ (62)**	$ (130)
Fair value, end of year – long-term portion	**(64)**	(21)
Total fair value, end of year	**$ (126)**	$ (151)

Based on December 31, 2010 pricing, a $1.00 change in the price per barrel of liquids would change the pre-tax unrealized risk management gain by $15 million.

The following table reconciles the changes in the fair value of financial instruments including the realized component (cash settlement) in the year:

	Year ended December 31	
Risk management	**2010**	2009
Balance, beginning of year	**$ (151)**	$ 442
Realized (gain) loss – commodity contracts	**20**	(344)
Unrealized gain (loss) – commodity contracts	**3**	(210)
Realized loss – other	**35**	37
Unrealized loss – other	**(33)**	(76)
Total fair value, end of year	**$ (126)**	$ (151)

Penn West had the following financial instruments outstanding as at December 31, 2010. Fair values were determined using external counterparty information, which is compared to observable market data.

	Notional volume	Remaining term	Pricing	Fair value
Crude oil				
WTI Collars	35,000 bbls/d	Jan/11 – Dec/11	US$80.06 to $91.98/bbl	$ (70)
WTI Collars	15,000 bbls/d	Jan/12 – Dec/12	US$83.67 to $96.32/bbl	(17)
Electricity swaps				
Alberta Power Pool	90 MW	Jan/11 – Dec/11	$63.16/MWh	(10)
Alberta Power Pool	45 MW	Jan/12 – Dec/12	$53.02/MWh	(2)
Alberta Power Pool	30 MW	Jan/12 – Dec/13	$54.60/MWh	(1)
Alberta Power Pool	20 MW	Jan/13 – Dec/13	$56.10/MWh	-
Alberta Power Pool	50 MW	Jan/14 – Dec/14	$58.50/MWh	(2)
Interest rate swaps				
	$500	Jan/11 – Dec/11	1.61%	(1)
	$600	Jan/11 – Jan/14	2.71%	(13)
	$50	Jan/11 – Jan/14	1.94%	-
Foreign exchange forwards				
19-month term	US$378	Jan/11 – Dec/11	1.06085 CAD/USD	23
8-year term	US$80	2015	1.01027 CAD/USD	1
10-year term	US$80	2017	1.00016 CAD/USD	1
12-year term	US$70	2019	0.99124 CAD/USD	1
15-year term	US$20	2022	0.98740 CAD/USD	-
Cross currency swaps				
10-year term	£57	2018	2.0075 CAD/GBP, 6.95%	(28)
10-year term	£20	2019	1.8051 CAD/GBP, 9.15%	(6)
10-year term	€10	2019	1.5870 CAD/EUR, 9.22%	(2)
Total				$ (126)

In 2011, Penn West entered into crude oil collars for 6,000 barrels per day for the period of March 2011 to December 2011 at US$79.50 per barrel to US$122.13 per barrel and on 10,000 barrels per day for 2012 at US$85.50 per barrel to US$115.56 per barrel. Additionally in 2011, Penn West entered into foreign exchange forward contracts to fix approximately $128 million of future US denominated senior, unsecured note repayments at an exchange rate of 1.0150 CAD/USD.

A realized loss of $14 million (2009 - $16 million) on electricity contracts has been included in operating costs for 2010.

Realized gains and losses on the interest rate swaps are recorded as financing costs. In 2010, an expense of $21 million (2009 – $21 million) was recorded to recognize the reduction in short-term floating interest rates compared to the fixed interest rates and terms transacted under our financial instruments.

In 2009, Penn West realized gains of $75 million on foreign exchange forward contracts related to oil collars.

11. Income taxes

As at December 31, 2010, the total future income tax liability of $838 million (2009 - $1,132 million) consisted of a $17 million current future income tax asset (2009 - $37 million) and an $855 million long-term future income tax liability (2009 - $1,169 million). The current portion of the future income tax asset represents future income taxes attributable to the unrealized risk management liability.

The net future income tax liability is comprised of the following:

	As at December 31	
	2010	2009
Future income tax liabilities		
Property, plant and equipment	**$ (1,671)**	$ (1,875)
Future income tax assets		
Risk management	**32**	39
Asset retirement obligations	**165**	146
Non-capital losses	**636**	558
Net future income tax liability	**$ (838)**	$ (1,132)
Future income tax asset	**17**	37
Future income tax liability	**$ (855)**	$ (1,169)

As an income trust, Penn West maintained an income tax status that permitted it to deduct distributions to unitholders.

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

	Year ended December 31	
	2010	2009
Loss before taxes	**$ (93)**	$ (522)
Combined statutory tax rate	**28.4%**	29.5%
Computed income tax recovery	**$ (26)**	$ (154)
Increase (decrease) resulting from:		
Net income attributable to the trust	**(109)**	(150)
Tax basis retained on restructuring	**(177)**	-
Tax rate reductions	**-**	(65)
Unit-based compensation	**13**	15
Unrealized foreign exchange	**(12)**	(29)
Previously unrecognized capital losses	**-**	(21)
Adjustment for previously enacted tax rates	**1**	54
Other	**(9)**	(28)
Future income tax recovery	**$ (319)**	$ (378)

Other includes the impact of true-ups to tax filings, prior year assessments received in the current year and revisions of previous estimates.

12. 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 Penn West 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 Penn West.

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

Unitholders' capital	**Units**		**Amount**
Balance, December 31, 2008	386,504,586	$	7,976
Issued on exercise of trust unit rights (1)	414,745		9
Issued to employee trust unit savings plan	2,579,500		37
Issued to distribution reinvestment plan	8,221,146		111
Issued to settle convertible debentures	1,498,247		19
Issued on trust unit offering (net of issue costs/tax)	17,731,000		240
Issued on Reece acquisition	4,689,513		59
Balance, December 31, 2009	421,638,737	$	8,451
Issued on exercise of trust unit rights (1)	**5,530,841**		**123**
Issued to employee trust unit savings plan	**2,025,699**		**42**
Issued to distribution reinvestment plan	**6,040,183**		**117**
Issued to settle convertible debentures	**922,580**		**18**
Issued on trust unit offering (net of issue costs/tax)	**23,524,209**		**426**
Balance, December 31, 2010	**459,682,249**	**$**	**9,177**

(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 or outstanding.

c) Contributed Surplus

Recorded contributed surplus related to the TURIP

	Year ended December 31	
	2010	2009
Balance, beginning of year	**$ 123**	$ 75
Unit-based compensation expense	**47**	52
Benefit on rights exercised [1]	**(32)**	(4)
Balance, end of year	**$ 138**	$ 123

(1) The exercise of trust unit rights is reflected as a reduction of contributed surplus and an increase to unitholders' capital.

13. Unit-based compensation

TURIP

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. The grant price of unit rights is administered to be equal to the volume-weighted average trading price of the trust units on the Toronto Stock Exchange for a five-trading-day period subsequent to the date of entitlement. 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, 2008	25,818,380	$ 22.88	$ 5.05
Granted	10,889,310	12.88	1.72
Exercised	(414,745)	13.38	2.17
Forfeited	(4,476,787)	21.68	4.99
Balance before reduction of exercise price	31,816,158	19.75	3.95
Reduction of exercise price for distributions paid	-	(2.10)	-
Outstanding, December 31, 2009	**31,816,158**	**$ 17.65**	**$ 3.95**
Granted	**7,689,930**	**19.90**	**3.55**
Exercised	**(5,530,841)**	**16.38**	**3.98**
Forfeited	**(2,609,769)**	**18.22**	**4.40**
Balance before reduction of exercise price	**31,365,478**	**18.38**	**3.82**
Reduction of exercise price for distributions paid	**-**	**(1.50)**	**-**
Outstanding, December 31, 2010	**31,365,478**	**$ 16.88**	**$ 3.82**

At December 31, 2010, exercisable trust unit rights totalled 13,895,742 (2009 - 11,155,528) at a weighted average exercise price of $17.52 (2009 - $20.01) and a weighted average grant date fair value of $4.48 (2009 - $4.92).

	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]
$9.00 - $15.99	7,849,736	$ 9.51	2.3	1,962,731	$ 9.54
$16.00 - $22.99	8,709,206	19.25	3.1	663,972	15.93
$23.00 - $29.99	9,920,765	17.60	1.0	7,233,343	16.87
$30.00 - $36.99	3,827,991	21.95	0.9	3,169,566	21.69
$37.00 - $44.99	1,057,780	26.93	1.4	866,130	26.94
	31,365,478	**$ 16.88**	**1.9**	**13,895,742**	**$ 17.52**

(1) Exercise prices are adjusted for distributions if certain conditions are met. The weighted average exercise price reflects the distribution adjustments, if any.
(2) Rights granted under the plan prior to November 13, 2006 expire after 6 years; rights granted after this date expire after 4 years.

Long-term retention and incentive plan ("LTRIP")

Penn West implemented an LTRIP in the first quarter of 2010 that allows Penn West employees to receive cash consideration based on Penn West's unit price. Eligible employees receive a grant of a specific number of trust units that vest over a three-year period with the cash value paid to the employee on each anniversary date. The cash consideration paid will vary depending upon the performance of the Penn West trust unit price on the Toronto Stock Exchange. If the service requirements are met, the cash consideration paid is based on the number of LTRIP awards vested and the five-day weighted average trading price of the trust units prior to the vest date plus cash distributions declared by Penn West during the vesting period.

	Year ended December 31	
LTRIP awards	**2010**	2009
Outstanding, beginning of year	**-**	-
Granted	**740,985**	-
Forfeited	**(40,316)**	-
Outstanding, end of year	**700,669**	-

Unit-based compensation expense

Unit-based compensation expense related to the TURIP is based on the fair value of rights issued on the grant date amortized over the remaining vesting period on a straight-line basis. Under the LTRIP, unit-based compensation is based on the intrinsic cost of the awards granted and is amortized based on a graded vesting schedule. The total unit-based compensation expense was allocated to operating expense and general and administrative expense as follows:

	Year ended December 31	
	2010	2009
TURIP		
Operating expense	**$ 11**	$ 13
General and administrative expense	**36**	39
LTRIP		
Operating expense	**4**	-
General and administrative expense	**4**	-
Unit-based compensation expense	**$ 55**	$ 52

The unit price used in the intrinsic cost calculation as at December 31, 2010 was $23.84 (2009 – N/A).

A Binomial Lattice option-pricing model was used to determine the fair value of trust unit rights granted under the TURIP with the following fair value per trust unit right and weighted average assumptions:

	Year ended December 31	
	2010	2009
Average fair value of trust unit rights granted (per unit)	**$ 3.55**	$ 1.72
Expected life of trust unit rights (years)	**3.0**	3.0
Expected volatility (average)	**32.2%**	32.1%
Risk-free rate of return (average)	**2.3%**	2.1%
Distribution yield (1)	**6.8%**	11.9%

(1) Represents distributions declared as a percentage of the Penn West's market price at the balance sheet date.

The expected volatility of the trust unit rights was based on the historical unit price volatility of Penn West. 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.

Employee Retirement 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. Up to December 31, 2010, these trust units could be issued from treasury at the five-day volume weighted trading price preceding the calendar month-end based on the Toronto Stock Exchange or purchased in the open market at prevailing market prices. Effective January 1, 2011, common shares will be purchased in the open market at prevailing market prices under this plan. During 2010, 2,025,699 treasury units (2009 – 2,579,500) were contributed to the plan at an average of $20.73 per unit (2009 – $14.53) and a total cost of $42 million (2009 – $37 million). No trust units were purchased in 2010 or 2009.

14. 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 and deductions. Distributions may be monthly or special and in cash or in trust units at the discretion of the Board of Directors.

	Year ended December 31	
Accumulated cash distributions	**2010**	2009
Balance, beginning of year	**$ 4,501**	$ 3,660
Distributions declared	**686**	841
Balance, end of year	**$ 5,187**	$ 4,501
Distributions per unit [(1)]	**$ 1.56**	$ 2.04
Accumulated cash distributions per unit, beginning of year	**16.22**	14.18
Accumulated cash distributions per unit, end of year	**$ 17.78**	$ 16.22

(1) Represents the annual sum of the per unit amounts declared monthly to unitholders.

15. Per unit amounts

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

	Year ended December 31	
	2010	2009
Basic	**441,813,114**	412,945,381
Diluted Impact	**5,800,081**	-
Diluted	**447,613,195**	412,945,381

The treasury stock method, using the average volume-weighted market price of trust units for each interim period, was applied to compute the number of dilutive units. In addition, contracts including convertible debentures that could be settled in cash or trust units are assumed to be settled in trust units if unit settlement is more dilutive.

For 2010, 16.4 million trust units (2009 – 31.8 million) that would be issued under the TURIP and 4.8 million trust units (2009 – 5.3 million) that would be issued on the conversion of the convertible debentures were excluded in calculating the weighted average number of diluted trust units outstanding at they were considered anti-dilutive.

16. Contractual obligations and commitments

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

	2011	2012	2013	2014	2015	Thereafter
Long-term debt	**$ -**	$ -	$ 778	$ 60	$ 251	$ 1,407
Transportation	**26**	15	14	9	5	-
Transportation ($US)	**4**	4	4	4	4	-
Power infrastructure	**30**	10	10	10	10	14
Drilling rigs	**9**	5	3	1	-	-
Purchase obligations (1)	**13**	13	13	11	10	8
Interest obligations	**154**	138	119	106	96	270
Office lease (2)	**$ 71**	$ 68	$ 66	$ 61	$ 60	$ 539

(1) These amounts represent estimated commitments of $51 million for CO_2 purchases and $17 million for processing fees related to interests in the Weyburn Unit.
(2) Future office lease commitments will be reduced by sublease recoveries totalling $413 million.

Penn West's syndicated credit facility is due for renewal on April 30, 2013. If Penn West is not successful in renewing or replacing the facility, it could be required to repay all amounts then outstanding on the facility or enter other loans including term bank loans. In addition, Penn West has an aggregate of $1.7 billion in senior notes maturing between 2014 and 2025. Penn West continuously monitors its credit metrics and maintains positive working relationships with its lenders and agents.

Convertible debentures with an aggregate principal amount of $255 million were outstanding on December 31, 2010 (2009 - $273 million). The principal amount and a significant portion of the interest payable on convertible debentures may, at the option of Penn West, be settled by the issuance of trust units.

17. Changes in non-cash working capital (increase) decrease

	Year ended December 31	
	2010	2009
Accounts receivable	**$ (15)**	$ 15
Other current assets	**14**	5
Deferred funding obligation	**15**	-
Accounts payable and accrued liabilities	**226**	(126)
	$ 240	$ (106)
Operating activities	**$ 85**	$ (27)
Investing activities	**155**	(79)
	$ 240	$ (106)

18. Business combinations

Sifton Energy Inc. (“Sifton”) Acquisition

On December 22, 2010, Penn West closed the acquisition of Sifton, a private oil and gas exploration company. The total acquisition cost was approximately $108 million, which included the assumption of approximately $23 million of debt and working capital.

Reece Energy Exploration Corp (“Reece”) Acquisition

On April 30, 2009, Penn West closed the acquisition of Reece Energy Exploration Corp. (“Reece”), an oil and gas exploration company. The acquisition was completed through a Plan of Arrangement wherein Reece shareholders received 0.125 of a Penn West trust unit for each Reece share. The total acquisition cost was approximately $101 million, which included the assumption of approximately $42 million of debt and working capital.

19. Related-party transactions

During 2010, Penn West paid $2 million (2009 – $2 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.

20. Capital management

Penn West manages its capital to provide a flexible structure to support production maintenance and organic growth and other operational strategies, maintain a strong financial position to capture business opportunities and maintain a stable distribution profile to its unitholders.

Unitholders’ equity, long-term debt and convertible debentures are defined as capital by Penn West. Unitholders’ equity includes unitholders’ capital, contributed surplus and deficit. Long-term debt includes bank loans and senior unsecured notes.

Management continuously reviews Penn West’s capital structure to ensure the objectives and strategies of Penn West are being met. The capital structure is reviewed based on a number of key factors including, but not limited to, the current market conditions, trailing and forecast debt to capitalization ratios and debt to funds flow and other economic risk factors. Distributions may be monthly or special and in cash or in trust units at the discretion of our Board of Directors.

The Company is subject to certain financial covenants under its unsecured, syndicated credit facility and the senior, unsecured notes. As at December 31, 2010, the Company was in compliance with all financial covenants; as follows:

(millions, except ratio amounts)	Year ended December 31 2010	2009
Components of capital		
Unitholders' equity	**$ 8,199**	$ 7,918
Long-term debt	**$ 2,496**	$ 3,219
Convertible debentures	**$ 255**	$ 273
Ratios		
Senior debt to pro forma EBITDA (2)	**1.8**	2.0
Total debt (9) to pro forma EBITDA (3)	**1.9**	2.0
Senior debt to capitalization (4)	**23%**	28%
Total debt (9) to capitalization (5)	**23%**	28%
Total debt (10) to capitalization (5)	**25%**	31%
Priority debt to consolidated tangible assets (6)	**-**	-
Pro forma EBITDA (1)	**$ 1,359**	$ 1,654
Credit facility debt and senior notes	**$ 2,496**	$ 3,219
Letters of credit	**2**	2
Total senior debt	**2,498**	3,221
Convertible debentures (7)	**26**	26
Total debt (9)	**2,524**	3,247
Convertible debentures (8)	**229**	247
Total debt (10)	**2,753**	3,494
Total unitholders' equity	**8,199**	7,918
Total capitalization	**$ 10,952**	$ 11,412

(1) Pro forma includes the effect of significant acquisitions and dispositions completed during the year as if they occurred at the beginning of the period.
(2) Less than 3:1 and not to exceed 3.5:1 in the event of a material acquisition.
(3) Less than 4:1.
(4) Not to exceed 50 percent except in the event of a material acquisition when the ratio is not to exceed 55 percent.
(5) Not to exceed 55 percent except in the event of a material acquisition when the ratio is not to exceed 60 percent.
(6) Priority debt not to exceed 15% of consolidated tangible assets.
(7) Convertible debentures not meeting the requirements for equity classification under lending agreements.
(8) Convertible debentures not meeting the requirements for equity classification under the 2007 Notes.
(9) Total debt as defined in the 2008 Notes, UK Notes, 2009 Notes, 2010 Q1 Notes, 2010 Q4 Notes and the syndicated bank facility agreements, which includes convertible debentures that do not meet the requirement for equity classification in these agreements.
(10) Total debt as defined in the 2007 Notes agreement, which includes convertible debentures that do not meet the requirements for equity classification in this agreement.

21. Subsequent event

Effective January 1, 2011, Penn West completed the previously announced plan of arrangement which resulted in its conversion to a publicly traded exploration and production company, Penn West Petroleum Ltd. (the "Company"). As a result of the conversion, the Company will now operate under the trade name of Penn West Exploration. Under the Plan of Arrangement, trust units were exchanged for common shares on a one-to-one basis. The Company was amalgamated under the laws of the Province of Alberta and will continue to carry on its business of oil and natural gas activities throughout western Canada. The Company's shares commenced trading in January 2011 on the TSX under the symbol "PWT" and on the NYSE, continuing under the symbol "PWE".

The following changes to Penn West's financial statements are expected as a result of the conversion in 2011 and subsequent.

Unitholders' capital

Following the one-to-one exchange of trust units for common shares, Unitholders' Capital will be re-classified to Shareholders' Capital.

Elimination of the consolidated deficit

Upon commencement of operations as a corporation, pursuant to the Plan of Arrangement, Penn West's recorded deficit was eliminated as at January 1, 2011.

Modifications of the TURIP

Under the Plan of Arrangement, the TURIP was amended whereby holders of "in-the-money" trust unit rights on December 31, 2010 could elect to receive, in exchange for each series of TURIP, an option (a "Restricted Option") and a right (a "Restricted Right"). Both components have the same terms and vesting provisions as a trust unit right and must be exercised simultaneously.

The Restricted Option entitles the option holder to acquire a common share of Penn West at a price of $23.84, the unit price at the close of business on December 31, 2010. Under Canadian GAAP, compensation expense related to the Restricted Option will be recorded at the fair value of the option granted at the grant date, amortized over the remaining vesting period on a straight-line basis.

Restricted Rights entitle holders to an amount equal to the lesser of the market price at the time of exercise and the unit price at the close of business on December 31, 2010 over the adjusted exercise price. The adjusted exercise price is calculated as the original grant price of the former trust unit right, less any cumulative distributions and dividends paid. Upon exercise of the restricted right, holders may elect to receive the value in cash or common shares. The Restricted Right will be accounted for as a liability. Under Canadian GAAP, compensation expense will be based on the intrinsic value of the awards expensed over the remaining life on a graded vesting schedule.

Trust unit rights that were "out-of-the money" on January 1, 2011 or that were not elected by the holder to receive a Restricted Option and a Restricted Right were exchanged for a common share right under the Common Share Rights Incentive Plan ("CSRIP"). Common share rights in the CSRIP will continue to follow the same terms as under the previous TURIP.

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INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Penn West Petroleum Ltd. (formerly the Unitholders of Penn West Energy Trust)

We have audited the consolidated financial statements of Penn West Energy Trust and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, the consolidated statements of operations and retained earnings (deficit) and cash flows for the years then ended, and notes comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Penn West Energy Trust and its subsidiaries a at December 31, 2010 and 2009 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

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Other Matters

Our audits were made for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The supplementary information entitled "Reconciliation of Canadian and United States Generally Accepted Accounting Principles" is presented for purposes of additional analysis and requirements under securities legislation. Such supplementary information has been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic consolidated financial statements taken as a whole.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, 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 17, 2011 expressed an unmodified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Chartered Accountants

Calgary, Canada
March 17, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Penn West Petroleum Ltd. (formerly the Unitholders of Penn West Energy Trust)

We have audited Penn West Energy Trust's ("the Company") internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company'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 Company'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.

A company'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. A company'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 company; (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 company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company'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 Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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 and the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 17, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Chartered Accountants
Calgary, Canada
March 17, 2011

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Reconciliation of Canadian and United States Generally Accepted Accounting Principles

Canadian Generally Accepted Accounting Principles ("GAAP") vary 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 ("Penn West") consolidated financial statements is described and quantified below:

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

	Year ended December 31	
	2010	2009
(CAD millions, except per unit amounts)		
Net and comprehensive Income (Loss) as reported in the Consolidated statements of operations – Canadian GAAP	**$ 226**	$ (144)
Adjustments		
Unit-based compensation (note (b))	**(78)**	20
Depletion and depreciation (note (a))	**832**	922
Income tax effect of the above adjustments	**(203)**	(218)
Net and other comprehensive income, U.S. GAAP, as adjusted	**$ 777**	$ 580
Net income per trust unit		
Basic	**$ 1.76**	$ 1.40
Diluted	**$ 1.74**	$ 1.40
Weighted average number of trust units outstanding (in millions)		
Basic	**441.8**	412.9
Diluted	**445.7**	414.2
Deficit - U.S. GAAP		
Balance, beginning of year - U.S. GAAP	**$ (5,061)**	$ (2,818)
Net income - U.S. GAAP	**777**	580
Change in redemption value of trust units (note (c))	**(2,287)**	(1,982)
Distributions declared	**(686)**	(841)
Balance, end of year - U.S. GAAP	**$ (7,257)**	$ (5,061)

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

December 31, 2010 (CAD millions)	Canadian GAAP	U.S. GAAP
ASSETS		
Current		
Accounts receivable	$ 386	$ 386
Future income taxes	17	17
Other	87	87
	490	490
Deferred funding obligation	678	678
Property, plant and equipment (note (a))	10,180	3,790
Goodwill	2,020	2,020
Future income taxes	-	655
	12,878	7,143
	$ 13,368	**$ 7,633**
LIABILITIES AND UNITHOLDERS' EQUITY (DEFICIENCY)		
Current		
Accounts payable and accrued liabilities	$ 743	$ 743
Distributions payable	41	41
Risk management	62	62
	846	846
Long-term debt	2,496	2,496
Convertible debentures	255	255
Asset retirement obligations	653	653
Unit rights liability (note (b))	-	165
Risk management	64	64
Future income taxes	855	-
Total liabilities	5,169	4,479
Unitholders' mezzanine equity (note (c))	-	10,411
Unitholders' equity (deficiency)		
Unitholders' capital (note (c))	9,177	-
Contributed surplus (note (b))	138	-
Deficit (note (c))	(1,116)	(7,257)
	8,199	(7,257)
	$ 13,368	**$ 7,633**

December 31, 2009 (CAD millions)	Canadian GAAP	U.S. GAAP
ASSETS		
Current		
Accounts receivable	$ 371	$ 371
Future income taxes	37	37
Other	101	101
	509	509
Property, plant and equipment (note (a))	11,347	4,125
Goodwill	2,020	2,020
Future income taxes	-	544
	13,367	6,689
	$ 13,876	**$ 7,198**
LIABILITIES AND UNITHOLDERS' EQUITY (DEFICIENCY)		
Current		
Accounts payable and accrued liabilities	$ 515	$ 515
Distributions payable	63	63
Risk management	130	130
	708	708
Long-term debt	3,219	3,219
Convertible debentures	273	273
Risk management	21	21
Asset retirement obligations	568	568
Unit rights liability (note (b))	-	40
Future income taxes	1,169	-
Total liabilities	5,958	4,829
Unitholders' mezzanine equity (note (c))	-	7,430
Unitholders' equity (deficiency)		
Unitholders' capital (note (c))	8,451	-
Contributed surplus (note (b))	123	-
Deficit (note (c))	(656)	(5,061)
	7,918	(5,061)
	$ 13,876	**$ 7,198**

The application of U.S. GAAP would have no effect on the statement of 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, less any impairment, 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 cash flows from proved plus probable reserves using forecast prices and costs, and the cost, less any impairment, of unproved properties.

The changes announced by the Securities and Exchange Commission in December 2008 to update the oil and gas reporting requirements became effective on December 31, 2009, resulting in a change in the impairment test under U.S. GAAP. Under the new guidelines, at the balance sheet date, 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 the average of prices on the first day of each month for the prior 12-month period, plus the cost, less any impairment of unproved properties. This effect of the new guidance was considered a change in estimate and was applied prospectively. Previously, prices were based on those at the balance sheet date. At December 31, 2010 and 2009, no impairment of Penn West's property, plant and equipment was indicated. Future net revenues in the impairment test were based on average prices of $3.94 per mcf (2009 - $3.74 per mcf) for natural gas and $71.32 per barrel (2009 - $57.72 per barrel) for liquids at December 31, 2010.

All of Penn West's reserves were evaluated or audited by independent petroleum engineers in both 2010 and 2009. 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. In determining the depletable base, the estimated future costs to be incurred in developing proved reserves are included and the estimated equipment salvage values and the cost, less any impairment, of unproved properties is excluded. Significant natural gas processing facilities, net of estimated salvage values, are depreciated using the declining balance method. 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. Due to the $8.1 billion impairment charge recorded in 2008 under only U.S. GAAP, depletion and depreciation was lower than that recorded under Canadian GAAP by $832 million in 2010 (2009 - $922 million). Depletion and depreciation per BOE as calculated under U.S. GAAP for the year ended December 31, 2010 was $7.68 (2009 - $9.15).

(b) Unit-based compensation

Trust unit rights incentive plan

Trust unit rights are treated as a liability under U.S. GAAP stated at the fair value of the grants determined by using a Binomial Lattice model at each reporting date. Compensation cost is recorded based on the change in fair value of the rights during each reporting period. When rights are exercised, the proceeds received plus the amount recorded as a trust unit rights liability are recorded as mezzanine equity. Penn West issues units from treasury to settle unit rights exercises.

Rights granted under the rights plan are considered equity awards for Canadian GAAP purposes. Unit-based compensation is based upon the fair value of rights issued, determined only on the grant date. This initial fair value is charged to income over the vesting period of the rights on a straight-line basis with a corresponding increase in contributed surplus. When rights are exercised, the consideration received plus the value recorded in contributed surplus is transferred to unitholders' equity. For the year ended December 31, 2010, compensation cost was $78 million higher (2009 - $20 million lower) under U.S. GAAP than under Canadian GAAP. The compensation cost for U.S. GAAP purposes was allocated as follows:

	Year ended December 31	
(millions)	**2010**	2009
Field employees	**$ 32**	$ 8
Corporate employees	**93**	24
Compensation expense	**$ 125**	$ 32

The total fair value under U.S. GAAP of non-vested trust unit rights and trust unit rights vested during the year was as follows:

	Year ended December 31		As at December 31	
	Total Fair Value (millions)		Weighted Remaining Contractual Life (years)	
	2010	2009	**2010**	2009
Non-vested options	**$ 56**	$ 72	**2.0**	1.9
Vested	**$ 37**	$ 31	**1.7**	1.3

If certain conditions are met, exercise prices are adjusted for distributions and employees may elect to exercise at the adjusted exercise price. If all employees elect to exercise at the adjusted exercise price, the total intrinsic value at December 31, 2010 for trust unit rights outstanding was $225 million (2009 - $96 million), for trust unit rights exercisable was $93 million (2009 - $17 million) and for trust unit rights exercised during the year was $46 million (2009 - $3 million).

Long-term retention and incentive plan ("LTRIP")

Awards granted under the LTRIP are recorded using the intrinsic value method under Canadian GAAP compared to the fair value method under U.S. GAAP. The difference between the valuation methods is insignificant; thus, no U.S. GAAP difference is considered to exist.

Earnings per share

A GAAP difference exists in calculating the number of diluted weighted average trust units considered outstanding for earnings per share purposes. The U.S. GAAP amount includes proceeds on assumed exercises of unit rights based on the fair value at each balance sheet date, compared to the fair value at only the date of grant under Canadian GAAP. This results in a different number of units included in the per unit calculations. For the year ended December 31, 2010, 14.5 million trust units (2009 – 25.2 million) that would be issued under the trust unit rights incentive plan and 4.8 million units that would be issued on the conversion of the convertible debentures (2009 – 4.8 million) were considered anti-dilutive.

(c) Unitholders' mezzanine equity

U.S. GAAP requires that trust units that are redeemable at the option of the unitholder, irrespective of the amounts which may be redeemed, 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. Penn West reclassified $10,411 million at December 31, 2010 (2009 - $7,430 million) as unitholders' mezzanine equity in accordance with U.S. GAAP.

Changes in unitholders' mezzanine equity, trust units issued net of redemptions, net income and distributions in a period are recognized as charges to deficit. Penn West recorded an increase of $2,287 million to deficit for the year ended December 31, 2010 (2009 - $1,982 million) to reflect the changes in the recorded amount of unitholders' mezzanine equity.

(d) Acquisitions

Penn West accounted for the Sifton Energy Inc. ("Sifton") and Reece Energy Exploration Corp. ("Reece") acquisitions as purchases. The consolidated financial statements of Penn West include the results of operations, funds flow and net income of Sifton from the closing date of December 22, 2010 and Reece from the closing date of April 30, 2009. If the Sifton acquisition had occurred on January 1, 2010 and 2009, and the Reece acquisition had occurred on January 1, 2009, Penn West would have realized the following U.S. GAAP pro forma results for the years ended:

	Year ended December 31	
(unaudited)	**2010**	2009
Revenue ($CAD millions)	**$ 2,527**	$ 2,388
Net income ($CAD millions)	**772**	578
Basic per unit	**1.75**	1.39
Diluted per unit	**$ 1.73**	$ 1.39

(e) Additional disclosure

Under Canadian GAAP, Penn West presents oil and natural gas revenues and royalty income prior to royalties payable in the Consolidated Statements of Operations and Retained Earnings (Deficit). Under U.S. GAAP, these items would be combined and presented on a net basis in the Consolidated Statements of Operations and Retained Earnings (Deficit).

(f) Income taxes

As at December 31, 2010, the total amount of Penn West's unrecognized tax benefits was approximately $10 million including $3 million of interest and penalties, which if recognized would affect Penn West'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 could occur from period to period.

The change in the amount of unrecognized tax benefits is as follows:

	Year ended December 31	
(millions)	**2010**	2009
Balance, beginning and end of year	**$ 10**	$ 10

Penn West and its entities are subject to income taxation and related audits in Canada. The tax years from 2004 to 2010 remain open to audit by Canadian tax authorities.

(g) Peace River Oil Partnership

Under U.S. GAAP, an exemption exists in Item 17(c)(2)(vii) of Form 20-F which allows Penn West to elect to follow the proportionate consolidation method of accounting for the partnership, if such treatment is allowable under Canadian GAAP. Penn West has chosen to utilize this exemption and accounts for the partnership on a proportionately consolidated basis under U.S. GAAP. At December 31, 2010, Penn West proportionately consolidated approximately $1 billion of property, plant and equipment.

SUPPLEMENTARY OIL AND GAS INFORMATION - (UNAUDITED)

The following disclosures in this section provide oil and gas information in accordance with the U.S. standard, “Disclosures about Oil and Gas Producing Activities”.

NET PROVED OIL AND NATURAL GAS RESERVES

Penn West engaged independent qualified reserve evaluators, GLJ Petroleum Consultants Ltd. (“GLJ”) and Sproule Associates Ltd. (“Sproule”), to evaluate Penn West’s proved developed and proved undeveloped oil and natural gas reserves or to audit Penn West’s evaluation thereof. As at December 31, 2010, all of Penn West’s oil and natural gas reserves are located in Canada and the United States of which less than one percent of our proved reserves are located in the United States. The changes in our net proved reserve quantities are outlined below.

Net reserves include Penn West’s remaining working interest and royalty reserves, less all Crown, freehold, and overriding royalties and other 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.

Proved developed reserves are those proved 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 to put the reserves on production. Proved 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 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, 2010
CONSTANT PRICES AND COSTS

Net Proved Developed and Proved Undeveloped Reserves [1]	Light and Medium Oil (mmbbl)	Heavy Oil (mmbbl)	Natural Gas (bcf)	Natural Gas Liquids (mmbbl)	Barrels of Oil Equivalent (mmboe)
December 31, 2009	228	49	693	16	408
Extensions & Discoveries	13	-	38	1	20
Improved Recovery	8	1	10	-	12
Technical Revisions	11	3	82	3	30
Acquisitions	7	3	19	1	14
Dispositions	(15)	(2)	(35)	-	(24)
Production	(21)	(6)	(122)	(3)	(51)
Change for the year	4	(2)	(8)	1	2
December 31, 2010	232	47	685	17	410
Developed	186	47	617	15	351
Undeveloped	46	1	69	2	59
Total [2]	232	47	685	17	410

YEAR ENDED DECEMBER 31, 2009
CONSTANT PRICES AND COSTS

Net Proved Developed and Proved Undeveloped Reserves [1]	Light and Medium Oil (mmbbl)	Heavy Oil (mmbbl)	Natural Gas (bcf)	Natural Gas Liquids (mmbbl)	Barrels of Oil Equivalent (mmboe)
December 31, 2008	214	39	875	18	416
Extensions & Discoveries	11	-	16	-	14
Improved Recovery	7	2	3	-	9
Technical Revisions	15	23	(34)	1	33
Acquisitions	3	-	6	-	4
Dispositions	(1)	(7)	(38)	(1)	(15)
Production	(21)	(8)	(135)	(3)	(54)
Change for the year	14	10	(182)	(3)	(9)
December 31, 2009	228	49	693	16	408
Developed	187	47	647	15	356
Undeveloped	42	2	47	1	52
Total [2]	228	49	693	16	408

(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)	2010	2009	2008
Proved oil and gas properties	$ 17,660	$ 17,536	$ 17,030
Unproved oil and gas properties	395	393	490
Total capitalized costs	18,055	17,929	17,520
Accumulated depletion and depreciation	(14,265)	(13,804)	(13,212)
Net capitalized costs	$ 3,790	$ 4,125	$ 4,308

COSTS INCURRED

For the years ended December 31, ($CAD millions)	2010	2009	2008
Property acquisition (disposition) costs [1]			
Proved oil and gas properties	$ (1,306)	$ (369)	$ (50)
Unproved oil and gas properties	102	19	128
Exploration costs [2]	210	79	140
Development costs [3]	881	546	780
Capital expenditures	(113)	275	998
Corporate acquisitions	139	116	5,525
Total expenditures	$ 26	$ 391	$ 6,523

(1) Acquisitions are net of disposition of properties.
(2) Cost of 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)	2010	2009	2008
Oil and gas sales, net of royalties and commodity contracts	$ 2,512	$ 2,154	$ 4,413
Lease operating costs and capital taxes	(959)	(979)	(865)
Transportation costs	(33)	(34)	(34)
Depletion, depreciation and accretion	(506)	(634)	(9,738)
Income taxes [1]	-	-	-
Results of operations	$ 1,014	$ 507	$ (6,224)

(1) Penn West is currently not cash 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 or audited by GLJ and Sproule of net proved reserves. Future cash inflows are computed based on 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 constant price assumptions and assume the continuation of existing economic conditions. Constant prices are the average of the first day prices of each month for the prior 12-month period. Future income taxes are calculated by applying statutory income tax rates. Penn West is currently not cash 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)	2010	2009
Future cash inflows	$ 24,117	$ 19,726
Future production costs	(11,765)	(11,090)
Future development costs	(1,306)	(1,047)
Undiscounted pre-tax cash flows	11,046	7,589
Future income taxes [1]	(583)	(22)
Future net cash flows	10,463	7,567
Less 10% annual discount factor	(4,382)	(3,170)
Standardized measure of discounted future net cash flows	$ 6,081	$ 4,397

(1) Penn West is currently not cash taxable.

($CAD millions)		2010		2009
Estimated future net revenue at beginning of year	$	4,397	$	3,770
Oil and gas sales during period net of production costs and royalties (1)		(1,512)		(1,708)
Changes due to prices and royalties related to forecast production (2)		643		1,635
Development costs during the period (3)		1,187		688
Changes in forecast development costs (4)		(1,108)		(476)
Changes resulting from extensions and improved recovery (5)		485		225
Changes resulting from discoveries (5)		-		4
Changes resulting from acquisitions of reserves (5)		208		47
Changes resulting from dispositions of reserves (5)		(233)		(166)
Discount factor (6)		440		377
Net change in income tax (7)		(115)		(1)
Changes resulting from technical reserves revision		459		152
All other changes (8)		1,231		(150)
Estimated future net revenue at end of year	$	6,081	$	4,397

(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. At December 31, 2010, Penn West was a Trust that would become taxable in 2011.
(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 17, 2011

/s/ William E. Andrew

William E. Andrew
Chief Executive Officer of Penn West Petroleum Ltd., successor to Penn West Energy Trust

Exhibit 99.6

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

I, Todd H. 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 17, 2011

/s/ Todd H. Takeyasu

Todd H. Takeyasu
Executive Vice President and Chief Financial Officer of Penn West Petroleum Ltd.,
successor to Penn West Energy Trust

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, 2010, 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., as successor to 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 Trust.

By: /s/ William E. Andrew
William E. Andrew
Chief Executive Officer of Penn West Petroleum Ltd.,
successor to Penn West Energy Trust

March 17, 2011

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, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Todd H. Takeyasu, Executive Vice President and Chief Financial Officer of Penn West Petroleum Ltd., as successor to 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 Trust.

By: /s/ Todd H. Takeyasu
Todd H. Takeyasu
Executive Vice President and Chief Financial Officer
of Penn West Petroleum Ltd., successor to Penn West Energy Trust

March 17, 2011

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

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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.

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

- our Independent Auditors' Report of Registered Public Accounting Firm to the Shareholders dated March 17, 2011 on the consolidated balance sheets of Penn West Energy Trust as at December 31, 2010 and 2009, and the consolidated statements of operations and retained earnings (deficit) and cash flows for the years then ended;

- our Independent Auditors' Report of Registered Public Accounting Firm to the Shareholders and Board of Directors dated March 17, 2011 on the consolidated balance sheets of Penn West Energy Trust as at December 31, 2010 and 2009, and the consolidated statements of operations and retained earnings (deficit) and cash flows for the years then ended; and

- our Report of Independent Registered Public Accounting Firm dated March 17, 2011 on Penn West Energy Trust's internal control over financial reporting as of December 31, 2010;

each of which is contained in this annual report on Form 40-F of Penn West Energy Trust for the fiscal year ended December 31, 2010.

We also consent to the incorporation by reference of the above mentioned audit reports in Penn West Energy Trust's registration statement on Form F-3 (No. 333-171675).

/s/ KPMG LLP

Calgary, Canada
March 17, 2011

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

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.
Leonard L. Herchen, P. Eng.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
Mark Jobin, P. Geol.
John E. Keith, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

LETTER OF CONSENT

Penn West Petroleum Ltd.
200, 207 – 9th Avenue SW
Calgary, AB T2P 1K3

Re: Engineer's Letter of Consent
Penn West Petroleum Ltd. ("**Penn West**")

We refer to: (i) our report dated January 28, 2011 and effective as of December 31, 2010, evaluating the crude oil, natural gas and natural gas liquids reserves and the net present value of future net revenue attributable to certain of the oil and natural gas assets effective as at December 31, 2010, and (ii) our report dated February 16, 2011 and effective as of December 31, 2010 consolidating the independent evaluations of Penn West's properties prepared in separate reports by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited (collectively, the "**Reports**").

We hereby consent to the use of our name and to the use of our Reports in Penn West's: (i) Annual Report (Form 40-F) for the year ended December 31, 2010; (ii) Registration Statement on Form F-3 (No. 333-171675); (iii) press release regarding 2010 year-end results; (iv) Annual Information Form for the year ended December 31, 2010, including but not limited to, disclosures in accordance with National Instrument 51-101; and (v) Supplementary Oil and Gas Information (SFAS 69) (collectively, the "**Disclosure Documents**").

We have read the Disclosure Documents and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Reports, or that is within our knowledge as a result of the services performed by us in connection with the Reports.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Bryan M. Joa

Bryan M. Joa, P. Eng.
Vice-President

Dated: March 17, 2011
Calgary, Alberta
CANADA

Exhibit 99.11

Ref.: 1772

March 17, 2011

Penn West Petroleum Ltd.
200, 207 – 9th Avenue SW
Calgary, AB T2P 1K3

Re: Engineer's Letter of Consent - Penn West Petroleum Ltd.

We refer to our report dated February 11, 2011 and effective as of December 31, 2010, evaluating the crude oil, natural gas and natural gas liquids reserves and the net present value of future net revenue attributable to certain of the oil and natural gas assets of Penn West Petroleum Ltd. effective as at December 31, 2010 (the "**Report**").

We hereby consent to the use of our name and to the use of our Report in Penn West Petroleum Ltd.'s:

(i) Annual Report (Form 40-F) for the year ended December 31, 2010;
(ii) Registration Statement on Form F-3 (No. 333-171675);
(iii) press release regarding 2010 year-end results;
(iv) Annual Information Form for the year ended December 31, 2010, including but not limited to, disclosures in accordance with National Instrument 51-101; and
(v) Supplementary Oil and Gas Information (SFAS 69)

(collectively, the "**Disclosure Documents**").

We have read the Disclosure Documents and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report, or that is within our knowledge as a result of the services performed by us in connection with the Report.

Sincerely,

SPROULE ASSOCIATES LIMITED

/s/ Robert N. Johnson
Robert N. Johnson, P.Eng.
Vice-President, Engineering and Director

Enclosure(s)
RNJ:nmt