PENGROWTH ENERGY TRUST
Form 40-F
March 09, 2010

Table of Contents

U.S. SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 40-F

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934.**

þ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2009 Commission File Number: 1-31253

PENGROWTH ENERGY TRUST
(Exact name of Registrant as specified in its charter)

Alberta, Canada
(Province or other jurisdiction of incorporation or organization)

1311	**None**
(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

Suite 2100, 222 Third Avenue S.W.
Calgary, Alberta Canada T2P 0B4
(403) 233-0224
(Address and telephone number of Registrant s principal executive offices)

Puglisi & Associates
850 Library Avenue, Suite 204
New York, Delaware 19711
(302)738-6680
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

copies to:

Brad D. Markel	**Edwin S. Maynard**
Bennett Jones LLP	**Andrew J. Foley**
4500 Bankers Hall East	**Paul, Weiss, Rifkind, Wharton & Garrison LLP**
855 2nd Street SW	**1285 Avenue of the Americas**
Calgary, Alberta T2P 4K7 Canada	**New York, New York 10019-6064 USA**
(403) 298-3100	**(212) 373-3000**

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
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.
None
(Title of Class)

For Annual Reports indicate by check mark the information filed with this Form:
þ Annual information form þ 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:

There were 289,834,790 Trust Units, of no par value, outstanding as of December 31, 2009.

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

Yes þ No o

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 (§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 o No o

This report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the registrant s Registration Statement on Form F-3 (File No. 333-143810) and the registrant s Registration Statement on Form F-10 (File No. 333-158580) under the Securities Act of 1933, as amended.

Table of Contents

DOCUMENTS FILED AS PART OF THIS ANNUAL REPORT

The following documents have been filed as part of this Annual Report on Form 40-F as Appendices hereto:

Appendix	Documents
A	Pengrowth Energy Trust Annual Information Form for the year ended December 31, 2009.
B	Management s Discussion and Analysis.
C	Consolidated Financial Statements of Pengrowth Energy Trust, including Management s Report to Unitholders, the Auditors Reports and note 24 thereof which includes a reconciliation of the Consolidated Financial Statements to United States generally accepted accounting principles.
D	Supplemental Unaudited Disclosures about Oil and Gas Producing Activities required under United States Generally Accepted Accounting Principles.
E	Pengrowth Energy Trust Code of Business Conduct and Ethics dated November 11, 2009.

CERTIFICATIONS AND DISCLOSURE REGARDING CONTROLS AND PROCEDURES

Certifications. See Exhibits 3, 4, 5 and 6 to this Annual Report on Form 40-F.

Disclosure Controls and Procedures. The required disclosure is included in the section entitled Disclosure Controls and Procedures contained in the Registrant s Management s Discussion and Analysis for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Management s Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the section entitled Internal Control Over Financial Reporting contained in the Registrant s Management s Discussion and Analysis for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the Auditors Report that accompanies the Registrant s Consolidated Financial Statements for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2009, there were no changes in the Registrant s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant s internal control over financial reporting.

Table of Contents

NOTICES PURSUANT TO REGULATION BTR

None.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Thomas A. Cumming, James D. McFarland, Michael S. Parrett and A. Terence Poole.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the Registrant has determined that each of Michael S. Parrett and A. Terence Poole, members of the Registrant s audit committee, qualify as audit committee financial experts for purposes of paragraph (8) of General Instruction B to Form 40-F. The board of directors has further determined that each of Mr. Parrett and Mr. Poole is also independent, as that term is defined in the Corporate Governance Listing Standards of the New York Stock Exchange. The Commission has indicated that the designation of each of Mr. Parrett and Mr. Poole as an audit committee financial expert does not make either of them an expert for any purpose, impose any duties, obligations or liabilities on them that are greater than those imposed on members of the audit committee and the board of directors who do not carry this designation or affect the duties, obligations or liabilities of any other member of the audit committee or the board of directors.

ADDITIONAL DISCLOSURE

Certain disclosure regarding the corporate governance practices of the Registrant, including disclosure of the Registrant s principal accountant fees and services, pre-approval policies and procedures, code of ethics and off-balance sheet arrangements, is included on pages 83,83,85 and 86, respectively, of the Annual Information Form contained in Appendix A. Disclosures regarding the Registrant s contractual obligations is included on page 25 of Management s Discussion and Analysis contained in Appendix B.

UNDERTAKING

Registrant 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.

CONSENT TO SERVICE OF PROCESS

Form F-X signed by the Registrant and its agent for service of process has been filed with the Commission together with Form F-10 (333-158580) in connection with its securities registered on such form.

Any changes to the name or address of the agent for service of process of the Registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the Registrant.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant 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.

Date: March 8, 2010	**PENGROWTH ENERGY TRUST** by its Administrator PENGROWTH CORPORATION
	By: /s/ Derek W. Evans Derek W. Evans President and Chief Executive Officer

Table of Contents

EXHIBIT INDEX

Exhibit	Description
1	Consent of Independent Registered Public Accounting Firm
2	Consent of GLJ Petroleum Consultants Ltd.
3	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
5	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934
6	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

Table of Contents

APPENDIX A
PENGROWTH ENERGY TRUST ANNUAL INFORMATION FORM FOR THE YEAR ENDED DECEMBER 31, 2009

Table of Contents

PENGROWTH ENERGY TRUST
ANNUAL INFORMATION FORM
For the year ended December 31, 2009
March 8, 2010

TABLE OF CONTENTS

Unless otherwise indicated, all of the information provided in this Annual Information Form is as at December 31, 2009.

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

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

Corporate

Board or **Board of Directors** refers to the board of directors of the Corporation;

Computershare refers to Computershare Trust Company of Canada;

Corporation refers to Pengrowth Corporation, the administrator of the Trust;

Credit Facility refers to Pengrowth s $1.2 billion extendible revolving term credit facility syndicated among eleven financial institutions;

Debenture refers to Pengrowth s six and a half percent convertible unsecured subordinated debentures assumed in connection with Pengrowth s strategic business combination with Esprit Energy Trust;

Debenture Indenture refers to the trust indenture relating to the Debentures entered into among Esprit Energy Trust, Esprit Exploration Ltd. and Computershare (as trustee), dated July 28, 2005 and assumed by Pengrowth on October 2, 2006 pursuant to the first supplemental trust indenture relating to the Debentures, entered into by the Trust, Esprit Energy Trust, Esprit Exploration Ltd., the Corporation and Computershare (as trustee);

Manager refers to Pengrowth Management Limited, the manager of the Trust and the Corporation prior to July 1, 2009;

Pengrowth , **we** , **us** **and** **our** refers to the Trust and all of its wholly-owned direct and indirect subsidiary entities or consolidated basis;

Royalty Indenture refers to the amended and restated royalty indenture of the Corporation, dated December 30, 2009, and supplemented on December 31, 2009;

Royalty Unitholder refers to a holder of Royalty Units;

Royalty Units refers to the royalty units of the Corporation created and issued pursuant to the Royalty Indenture;

SIFT Legislation refers to the Specified Investment Flow-Through legislation and has the meaning ascribed thereto under *Certain Canadian Federal Income Tax Considerations* ;

Trust refers to Pengrowth Energy Trust;

Trust Indenture refers to the amended and restated trust indenture of the Trust, dated July 1, 2009;

Trust Units refers to the trust units of the Trust created and issued pursuant to the Trust Indenture; and

Unitholders refers to holders of Trust Units, class A trust units and special units, as the context requires.

Engineering

Company Interest is equal to Pengrowth s gross interest plus Pengrowth s Royalty Interest; that is, the Working Interest share of production or reserves prior to the deduction of royalties plus any royalty interest in production or reserves at the wellhead;

Contingent Resources are those quantities of petroleum estimated, on a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. Contingent Resources do not constitute, and should not be confused with, reserves;

Developed Non-Producing Reserves refers to 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;

Developed Producing Reserves refers to those reserves 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;

Developed Reserves refers to 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 to put the reserves on production; the developed category may be subdivided into Developed Producing Reserves and Developed Non-Producing Reserves;

future net revenue refers to the estimated net amount to be received with respect to the development and production of reserves computed by deducting, from estimated future revenues, estimated future royalty obligations, costs related to the development and production of reserves and abandonment and reclamation costs (corporate general and administrative expenses and financing costs are not deducted);

GLJ refers to GLJ Petroleum Consultants Ltd., independent petroleum consultants, Calgary, Alberta;

GLJ Report refers to the report prepared by GLJ, dated February 5, 2010 with an effective date of December 31, 2009;

gross with respect to: (i) Pengrowth s interest in production or reserves, refers to Pengrowth s Working Interest (operating or non-operating) share before the deduction of royalties and without including any royalty interests (excluding Pengrowth s Royalty Interest reserves); (ii) Pengrowth s wells, refers to the total number of wells in which Pengrowth has an interest; and (iii) Pengrowth s properties, refers to the total area of properties in which Pengrowth has an interest;

net with respect to: (i) Pengrowth s interest in production or reserves, refers to Pengrowth s Working Interest (operating or non-operating) share after the deduction of royalty obligations, plus Pengrowth s royalty interests in production or reserves; (ii) Pengrowth s interest in wells, refers to the number of wells obtained by aggregating Pengrowth s working interest in each of its gross wells; and (iii) Pengrowth s interest in a property, refers to the total area in which Pengrowth has an interest multiplied by the working interest owned by Pengrowth;

Possible Reserves are those additional reserves that are less certain to be recovered than Probable Reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible Reserves;

Probable Reserves refers to 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;

Proved Reserves refers to 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;

Remaining Reserve Life refers to the expected productive life of the property or fifty years, whichever is less;

Table of Contents

Reserve Life Index refers to the number of years determined by dividing the Company Interest Total Proved Plus Probable Reserves of a property by the 2010 Company Interest estimated Total Proved Plus Probable production from such property. The reserves and the 2010 estimated production for such property come from the GLJ Report;

reserves refers to estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and specified economic conditions which are generally accepted as being reasonable and shall be disclosed; reserves are classified according to the degree of certainty associated with the estimate (e.g., proved, probable);

Royalty Interest refers to Pengrowth s interest in production and payment that is based on the gross production at the wellhead; a royalty is paid in either cash or kind, but is paid on a value calculated at the wellhead;

Total Proved Plus Probable Reserves or **P+P** means the aggregate of Proved Reserves and Probable Reserves;

Undeveloped Reserves refers to those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. the cost of drilling a well) is required to render them capable of production; they must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned; and

Working Interest refers to the percentage of undivided interest, excluding royalty interest, held by Pengrowth in an oil and gas property.

Abbreviations

API refers to the American Petroleum Institute;

ºAPI refers to an indication of the specific gravity of crude oil measured on the API gravity scale;

bbl , **Mbbl** , **MMbbl** and **Bbbl** refers to barrels, thousands of barrels, millions of barrels and billions of barrels, respectively;

bblpd refers to barrels per day;

boe , **Mboe** and **MMboe** refers to barrels of oil equivalent, thousands of barrels of oil equivalent and millions of barrels of oil equivalent, respectively, on the basis of one boe being equal to one barrel of oil or NGLs or six Mcf of natural gas;

boepd refers to barrels of oil equivalent per day;

bwpd refers to barrels of water per day;

CBM refers to natural gas, primarily methane, producible from coal seams, commonly called coal bed methane;

EOR refers to enhanced oil recovery;

EDGAR refers to the Electronic Data Gathering Analysis and Retrieval System maintained by the SEC;

GAAP or **Canadian GAAP** refers to generally accepted accounting principles in Canada;

$M and **$MM** refers to thousands of dollars and millions of dollars, respectively;

Table of Contents

MMBtu refers to million British thermal units;
Mcf , **MMcf** and **Bcf** refers to thousands of cubic feet, millions of cubic feet and billions of cubic feet, respectively;
Mcfe refers to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil or one barrel of NGLs being equal to six Mcf of natural gas;
Mcfpd and **MMcfpd** refers to thousands of cubic feet per day and millions of cubic feet per day, respectively;
NGLs refers to natural gas liquids;
NYSE refers to the New York Stock Exchange;
SAGD refers to steam assisted gravity drainage;
SEC refers to the United States Securities and Exchange Commission;
SEDAR refers to the System for Electronic Document Analysis and Retrieval of the Canadian Securities Administrators;
Tax Act refers to the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time;
TSX refers to the Toronto Stock Exchange; and
WTI refers to West Texas Intermediate.

Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversation ratio of six Mcf of natural gas to one barrel of crude oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSION

In this Annual Information Form, measurements are given in standard imperial or metric units only. The following table sets forth certain standard conversions:

To Convert From	To	Multiply by
Mcf	cubic metre	28.174
bbl	cubic metre	0.159
MMBtu	gigajoule	1.0546
cubic metre	bbl	6.29
metre	feet	3.281
mile	kilometre	1.609
kilometre	mile	0.621
acre	hectare	0.405

Table of Contents

PRESENTATION OF OUR FINANCIAL INFORMATION

Financial information in this Annual Information Form has been prepared in accordance with Canadian GAAP. Canadian GAAP differs in some significant respects from United States generally accepted accounting principles and thus our financial statements may not be comparable to the financial statements of U.S. companies. The principal differences as they apply to us are summarized in note 24 to our audited annual consolidated financial statements for the year ended December 31, 2009, which are available on the SEDAR website at www.sedar.com and in our current Form 40-F, which is available through EDGAR at the SEC s website at www.sec.gov.

Unless otherwise stated, all sums of money referred to in this Annual Information Form are expressed in Canadian dollars.

PRESENTATION OF OUR RESERVE INFORMATION

National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) of the Canadian Securities Administrators permits oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only Proved Reserves but also Probable Reserves, Possible Reserves and Contingent Resources, and to disclose reserves and production on a gross basis before deducting royalties. Probable Reserves and Possible Reserves are of a higher risk and are less likely to be accurately estimated or recovered than Proved Reserves. Contingent Resources are higher risk than Probable Reserves and Possible Reserves and are less likely to be accurately estimated or recovered than Probable Reserves or Possible Reserves. Because we are permitted to prepare this Annual Information Form in accordance with Canadian disclosure requirements, we have disclosed in this Annual Information Form reserves designated as Probable Reserves, Possible Reserves and Contingent Resources and have disclosed reserves and production on a gross basis before deducting royalties.

Current SEC reporting requirements permit oil and gas companies to disclose probable and possible reserves, in addition to the required disclosure of proved reserves. If this Annual Information Form was required to be prepared in accordance with U.S. disclosure requirements, the SEC s requirements would prohibit Contingent Resources from being disclosed. Under current SEC requirements, net quantities of reserves are required to be disclosed, which requires disclosure on an after royalties basis and does not include reserves relating to the interests of others. For a description of these and additional differences between Canadian and U.S. standards of reporting reserves, see *Risk Factors 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* . Additional information prepared in accordance with the U.S. Financial Accounting Standards Board s Accounting Standards Update (Extractive Activities-Oil and Gas (Topic 932)) relating to our oil and gas reserves is set forth in our current Form 40-F, which is available through EDGAR at the SEC s website at www.sec.gov.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements within the meaning of securities laws, including the safe harbour provisions of Canadian securities legislation and the United States *Private Securities Litigation Reform Act of 1995*. Forward-looking information is often, but not always, identified by the use of words such as anticipate , believe , expect , plan , intend , forecast , target , project , guidance , may , will , should or similar words suggesting future outcomes or language suggesting an outlook. Forward-looking statements in this Annual Information Form include, but are not limited to, benefits and synergies resulting from our corporate and asset acquisitions, business strategy and strengths, goals, focus and the effects thereof, acquisition criteria, capital expenditures, reserves, reserve life indices, estimated production, production additions from our 2010 development program, remaining producing reserves lives, operating expenses, royalty rates, net present values of future net revenue from reserves, commodity prices and costs, exchange rates, the impact of contracts for commodities, development plans and programs, tax horizon, future income taxes, taxability of distributions, the impact of proposed changes to Canadian tax legislation or U.S. tax legislation, our proposed conversion to a dividend paying corporation, abandonment and reclamation costs, government royalty rates (including estimated increase in royalties paid and estimated decline in net present value of reserves and 2010 cash flows) and expiring acreage.

Table of Contents

Statements relating to reserves are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can profitably be produced in the future.

Forward-looking statements and information are based on our current beliefs as well as assumptions made by, and information currently available to, us concerning anticipated financial performance, business prospects, strategies, regulatory developments, future oil and natural gas commodity prices and differentials between light, medium and heavy oil prices, future oil and natural gas production levels, future exchange rates, the proceeds of anticipated divestitures, the amount of future cash distributions paid by the Trust, the cost of expanding our property holdings, our ability to obtain equipment in a timely manner to carry out development activities, our ability to market our oil and 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 acquisition, development and exploration activities. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; our ability to replace and expand oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; counterparty risk; compliance with environmental laws and regulations; changes in tax and royalty laws; the failure to qualify as a mutual fund trust; our ability to access external sources of debt and equity capital, the implementation of International Financial Reporting Standards (IFRS); and the implementation of greenhouse gas (GHG) emissions legislation. Further information regarding these factors may be found under the heading *Risk Factors* in this Annual Information Form, under the heading *Business Risks* in our Management s Discussion and Analysis for the year ended December 31, 2009, and in our most recent consolidated financial statements, management information circular, quarterly reports, material change reports and news releases.

Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Pengrowth, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Furthermore, the forward-looking statements contained in this Annual Information Form are made as of the date of this document and we do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement.

Table of Contents

PENGROWTH ENERGY TRUST

Introduction

The Trust is an energy investment trust that was created under the laws of the Province of Alberta on December 2, 1988. The purpose of the Trust is to pay distributions to our Unitholders and to purchase and hold Royalty Units and other securities issued by the Corporation, its wholly-owned subsidiary, as well as other investments and to issue Trust Units to members of the public. The Corporation directly and indirectly acquires, owns and manages Working Interests and Royalty Interests in oil and natural gas properties. The head office and registered office of the Trust is located at 2100, 222 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.

The Trust

The Trust is governed by the Trust Indenture. Under the Trust Indenture, the Trust has issued Trust Units and class A trust units to Unitholders. Each Trust Unit and class A trust unit represents a fractional undivided beneficial interest in the Trust. Our Unitholders receive monthly distributions as declared by the Board in respect of the royalty (Royalty) the Corporation pays to the holder of the Royalty Units, and in respect of investments that are held by the Trust.

The Trust holds 100 percent of the outstanding common shares in the capital of the Corporation. The Trust also holds all of the Royalty Units issued by the Corporation. The Trust holds other permitted investments, including indebtedness of the Corporation and oil and gas processing facilities. The Trust s share of royalty income, together with any lease, interest and other income of the Trust, less general and administrative expenses, management fees, debt repayment, taxes and other expenses (provided that there is no duplication of expenses already deducted from royalty income), forms the cash to be distributed by the Trust.

The Corporation

The Corporation was created under the laws of the Province of Alberta on December 30, 1987. The name of the Corporation was changed from Pengrowth Gas Corporation to Pengrowth Corporation in 1998. The Corporation presently has 1,100 common shares issued and outstanding, all of which are owned by the Trust. These common shares do not participate in any distributions from the Corporation.

The Corporation acquires, owns and operates Working Interests and Royalty Interests in oil and natural gas properties. The Corporation invests a percentage of cash flow on operated, low cost, low risk, repeatable drilling opportunities in the WCSB. The Corporation has issued Royalty Units to the Trust, which entitles the Trust to receive a 99 percent share of the royalty income related to the oil and natural gas interests of the Corporation.

As at December 31, 2009, we had 596 permanent employees.

Prior to July 1, 2009, the Trust and the Corporation were managed by the Manager pursuant to a management agreement among the Manager, the Trust, the Corporation and Computershare, as trustee (the Management Agreement). On June 30, 2009, the Management Agreement expired. See *Pengrowth Energy Trust Recent Developments Expiry of the Management Agreement* .

Table of Contents

Intercorporate Relationships

The following diagram illustrates our organizational structure as of January 1, 2010:

Business Strategy

Our goal over the longer term is to maximize value creation for Unitholders through reinvesting a portion of our cash flow on our oil and gas properties while continuing our cash distributions. In 2009, our business model increased the emphasis on capital reinvestment following a review of the best opportunities for value creation on our existing asset base. This value creation strategy was announced on October 1, 2009 and balances our distributions with our capital program and places an emphasis of living within Pengrowth s cash flow. Our increased capital program focuses on Pengrowth s short and medium term inventory of low cost, low risk resource plays that have the ability to enhance reserves and production, including utilizing new technologies, while achieving operational efficiencies and maintaining cost discipline. See *Pengrowth Energy Trust Recent Developments Changes to our Value Creation Strategy* . We will continue acquiring companies and assets and anticipate financing those acquisitions with a prudent combination of debt and equity. We are positioning ourselves to continue with this strategy as a dividend paying corporation after we convert from a trust in response to the SIFT Legislation.

Our operational expertise is in the Western Canadian Sedimentary Basin (WCSB). We rely on our expertise to partially offset production declines in our mature oil and gas properties as well as develop new production in less mature oil and gas properties. We have an advantage through our expertise in horizontal well carbonate reef multi-stage fracturing technology use, EOR technologies and waterflood optimization. Our inventory of undeveloped land and opportunities on producing properties provide future drilling opportunities for the short-term and mid-term. In the mid-term, we anticipate the development of CO_2 EOR at a number of fields with the initial development at Judy Creek. In the mid-term and long-term, we anticipate developing additional unconventional resource plays for oil and gas, including the Lindbergh SAGD project and the Horn River shale gas property.

We will continue to prepare Pengrowth in 2010 for a transition into a dividend paying corporation on or before January 1, 2011. For 2010, we have established a prudent capital spending level that is higher than the previous year, but flexible in an uncertain commodity price environment. Over the long term, we will target a balance of capital spending that can maintain or modestly grow reserves on a debt adjusted per unit basis. As we address the challenges of transitioning to a dividend paying corporation and the ordinary declines in production from our existing assets through development capital projects, we will create key focus areas where the deployment of newer technology can add production and reserves in a repeatable and scalable manner.

Table of Contents

We prioritize our development investments based on each project s:

- net present value of future cash flow as compared to the capital invested;
- rate of return of future cash flows;
- potential for continued, repeatable and scalable development; and
- investments necessary to maintain existing facilities and wells.

Recent Developments

The following is a description of the significant developments in our business since January 1, 2009.

2010 Forecast Capital, Production and Operating Costs

On December 17, 2009, we released the details of our 2010 capital expenditure program and provided guidance on production and operating costs for 2010. Our 2010 development capital expenditure program is expected to be up to $285 million, excluding Alberta drilling credits. We will continue to monitor and adjust capital investment levels in order to ensure that we optimize value, operate within our cash flow and have the flexibility to take advantage of acquisition opportunities.

The table below describes the forecasted capital, production and operating costs for 2010:

Planned Capital Expenditures		**($ millions)**
Drill, Complete and Tie-In	$	192
Major Projects (Lindbergh, Horn River)		28
Land and Seismic		8
Total Development Capital	**$**	228
Facilities Maintenance		50
Total Development Capital Including Facilities	**$**	278
Other (e.g., IT)		7
Total Capital	**$**	285
Average Daily Production Volume (boepd)	**74,000**	**76,000**(1)
Operating Costs (per boe)	**$**	**14.40**(2)
General and Administrative Costs (per boe)	**$**	**2.23**(2)

Notes:

(1) The 2010 estimate excludes potential additions arising from acquisitions or reductions from dispositions.

(2) Assuming production targets for 2010 are achieved.

The 2010 capital program is focused 70 percent on oil development and liquids rich gas projects, with the largest portion directed toward tight carbonate and heavy oil projects. Approximately $82 million will be spent on operated tight carbonate plays including $27 million at Carson Creek and $21 million at Judy Creek. We also plan to spend $15.5 million on our heavy oil projects, in addition to an expenditure of $15 million for our pilot SAGD oil project at Lindbergh. At our shale gas property at Horn River, $12 million has been budgeted to drill three wells in the winter of

2009 and 2010.

Our 2010 operating costs of approximately $395 million are expected to slightly increase on a year over year basis by $14 million or four percent. Although we anticipate an increase in power and labour costs, it is expected that the remainder of our other operating costs will remain stable. The anticipated increases in power and labour costs combined with an anticipated lower average production rate for 2010 has resulted in an estimated $14.40 per boe operating cost for 2010, a ten percent increase when compared to the 2009 full year amount of $13.13 per boe. We will continue to actively manage our power usage, the single largest component of our operating costs, through our power shedding and hedging programs.

Total general and administrative (G&A) costs are expected to increase slightly for 2010 to $2.23 per boe when compared to full year 2009 cost of $2.14 per boe due to declining production guidance for 2010 versus 2009. Included in our 2010 G&A forecast are non-cash G&A costs of approximately $0.37 per boe. Total costs associated with our anticipated conversion from a trust to a dividend paying corporation are estimated to be approximately $1 million and have been included in the 2010 G&A forecast.

The Board of Directors considered a number of factors in approving the capital budget for 2010, including anticipated cash flow from operations based upon forecast commodity prices, the level of distributions paid by the Trust, our level of indebtedness, access to capital and cost of capital. The 2010 budget relies on undistributed cash from operations to fully fund the capital program.

On January 1, 2009, the Government of Alberta implemented the new royalty framework (the New Royalty Framework) and the transitional royalties (the Transitional Royalties), which apply to wells drilled after November 18, 2008 and to production from those wells through

December 31, 2013. Approximately 74 percent of our reserves are from properties where royalties are paid to the Government of Alberta. The Alberta Government s royalties do affect how we allocate capital as the royalties impact both the net present value and rate of return. On March 3, 2009, the Government of Alberta announced an incentive program that was initially intended to be in place for one-year but was subsequently extended on June 25, 2009 for an additional year. This program applies to wells which begin drilling on or after April 1, 2009 and before April 1, 2011. The new well royalty reduction incentive program (NWRR) provide a $200 per meter drilled royalty credit as well as a maximum five percent royalty rate for the first year of production. The drilling credits are limited based on a sliding scale of 2008 Alberta production. Our 2010 credit is limited to twenty percent of Alberta Crown royalties paid or an estimated credit of $40 million. The five percent royalty rate extends for one year unless 50,000 barrels of oil or 500 million cubic feet of gas is produced. In either of those instances, the five percent royalty rate ceases.

Convertible Debentures

On December 16, 2009, we announced that we would redeem the outstanding Debentures in accordance with their terms of issuance. On January 15, 2010, the Debentures were redeemed at a cash redemption price of $1,025 per $1,000 principal value for a total cost of $76,609,525, plus accrued and unpaid interest to the redemption date. The cash redemption amount was funded with incremental borrowings from the Credit Facility.

Equity Financing

On October 23, 2009, we completed a bought deal public offering of 28,847,000 Trust Units at a price of $10.40 per Trust Unit for total gross proceeds of approximately $300 million. The net proceeds of approximately $285 million were used to repay indebtedness under the Credit Facility and for general corporate purposes.

Gross Overriding Royalties Created

We created gross overriding royalties (GORR) on a number of properties that have approximately 8,000 boepd of production in anticipation of selling the GORR. These GORRs are effective October 1, 2009 and cause five percent of the revenue to be paid.

Result Acquisition

On October 1, 2009, we acquired all of Result Energy s interests in the Horn River Basin for $11 million dollars. We acquired 28,842 net acres and Result s interest in one standing wellbore.

Reduction in Distributions

A reduction in distributions from $0.17 per Trust Unit to $0.10 per Trust Unit per month was announced on February 19, 2009 commencing with the March 16, 2009 distribution. The Board of Director s stated objective in making this reduction in distributions was exercising financial prudence in uncertain times. On October 1, 2009, we announced changes to our value creation strategy to focus on investing a larger percentage of cash flow on operated, low cost, low risk, repeatable drilling opportunities in the WCSB. To provide funds for our expanded capital program, while maintaining fiscal discipline, we reduced our November 16, 2009 cash distribution by 30 percent or $0.03 per Trust Unit to $0.07 per Trust Unit.

Changes to our Value Creation Strategy

On October 1, 2009, we announced changes to our value creation strategy to focus on investing a larger percentage of cash flow on operated, low cost, low risk, repeatable drilling opportunities in the WCSB. The following are some of the key changes that will be implemented as part of the value creation strategy:

- Shifting internal capital expenditures on our existing high quality asset base to focus on existing low cost, low risk plays (Carson Creek, shallow gas, CBM) as well as to identify, test and develop other resource plays where repeatable, predictable and scalable results can be achieved.

- Increasing capital expenditures as a percentage of cash flow to facilitate higher reinvestment levels on our existing assets as well as to advance longer term value of our Lindbergh, EOR and Horn River resource plays.

- Adopting a sustainable business model where distributions plus capital expenditures are equal to cash flow.

- Enhancing our low cost culture ensuring a high level of capital efficiency and cost discipline.

Reducing debt to levels more consistent with energy trust averages projected for the next 18 months.

Acquiring other WCSB assets with low cost, low risk, repeatable, predictable and scalable drilling opportunities.

Maintaining or modestly growing production and reserves on a debt adjusted per unit basis.

These changes resulted from our strategic review of the best opportunities for value creation on our existing asset base and a broader review of unconventional value creation opportunities in the WCSB.

Our track record of value creation with the drill bit since 2006, as evidenced by our low finding and development costs, and a review of our current unfunded projects, supports increased levels of capital re-investment.

Taxability of Distributions Paid to U.S. Residents

Effective July 1, 2009, the Trust elected to be treated as a corporation for U.S. federal income tax purposes. Prior to July 1, 2009, distributions paid to U.S. residents were treated as partnership distributions for U.S. federal tax purposes and were subject to a 15 percent Canadian withholding tax to the extent that such amounts represented a distribution of Pengrowth s income. Pursuant to the Tax Act, distributions to U.S. resident Unitholders of amounts in excess of Pengrowth s income (e.g., returns of capital) were also subject to a 15 percent Canadian withholding tax. On September 21, 2007, Canada and the United States signed the fifth protocol to the Canada-U.S. Convention dated September 21, 2007 (the Protocol) to the Canada-United States Tax Convention, 1980 (the Canada-U.S. Convention), which would have increased the amount of Canadian withholding tax from 15 to 25 percent on distributions of income. The increase would have become effective on January 1, 2010. Under Article IV(7)(b) of the Protocol, U.S. resident Unitholders are denied certain of the benefits under the Canada-U.S. Convention which would otherwise reduce the withholding tax on distributions of Pengrowth s income from 25 to 15 percent. The effect of Pengrowth s election to be treated as a corporation is to maintain the current withholding tax rate of 15 percent and not subject its U.S. investors to an increase in the 15 percent withholding tax on their distributions starting January 1, 2010.

Expiry of the Management Agreement

The Unitholders and the Royalty Unitholders approved the Management Agreement (the Management Agreement) at the annual and special meetings held on June 17, 2003. Pursuant to the Management Agreement, the Manager provided advisory, management, and administrative services primarily to the Trust and the Corporation. The Management Agreement expired on June 30, 2009. On October 10, 2007, a special committee of the Board of Directors, comprised of all independent members of the Board, was formed for the purpose of advising the Board in connection with the orderly transition to a traditional corporate governance structure at the end of the term of the Management Agreement. The Management Agreement expired on June 30, 2009 and the Board and executive officers of the Corporation now have exclusive oversight over the business, assets and operations of Pengrowth. There is no ongoing relationship between Pengrowth and the Manager.

Board of Directors and Management Changes

On May 25, 2009 Derek W. Evans was appointed as the President and Chief Operating Officer and as a director of the Corporation. On September 13, 2009, we announced the appointment of Derek W. Evans as President and Chief Executive Officer of the Corporation. Mr. Evans appointment as Chief Executive Officer followed the retirement of James S. Kinnear as Chairman and Chief Executive Officer. Mr. Kinnear remains on the Board of Directors.

On November 11, 2009, John Zaozirny, Vice Chairman and Lead Independent Director, was appointed as the Chairman of the Board of Directors.

On January 8, 2010, we announced the appointment of James D. McFarland to the Board of Directors.

Amendments to the Trust Indenture and the Unanimous Shareholder Agreement

At our most recent annual and special meeting of Unitholders, held on June 9, 2009, Unitholders approved an extraordinary resolution authorizing certain amendments to the Trust Indenture and to the Corporation s unanimous shareholder agreement. The purposes of such amendments are to increase the grant of responsibility and authority to the Corporation to administer the business, affairs and operations of the Trust and to amend the right of the Manager to nominate members of the board of directors of the Corporation. The amendments reflect that the Manager ceased to be the manager of the Trust upon the expiry of the Management Agreement on June 30, 2009. See *Trust Units The Trustee* .

SIFT Legislation Considerations

On October 31, 2006, the Department of Finance (Canada) (Finance) announced proposed tax measures which will materially and adversely change the manner in which Pengrowth is taxed and will also change the character of the distributions to Unitholders for Canadian federal income tax purposes. On June 22, 2007, the SIFT Legislation became law when Bill C-52 received royal assent. It is expected that the SIFT Legislation will apply to Pengrowth and its Unitholders commencing in 2011, provided that Pengrowth does not exceed the limits on normal growth prior to that time.

On July 14, 2008, Finance announced proposals that would permit the conversion of a trust to a corporation on a tax-deferred basis (the SIFT Conversion Rules). Finance also announced changes to these rules on November 28, 2008 and introduced a notice of ways and means motion on January 27, 2009 implementing the SIFT Conversion Rules. On March 12, 2009, the SIFT Conversion Rules received royal assent in Bill C-10. The SIFT Conversion Rules contain legislation which permits a conversion of a trust to a corporation to occur on a tax-deferred basis under two general types of commercial structures: (i) an exchange transaction, whereby unitholders of a trust would exchange their units for securities issued by a corporation, or (ii) a dissolution transaction, whereby the trust would distribute the securities it holds in its corporate subsidiary to its unitholders in consideration for the redemption of the unitholders units. Under either scenario, it is expected that the shares received by the unitholders would be issued by the new public entity and would be listed on the TSX or some other public stock exchange. The SIFT Conversion Rules also include certain provisions which permit the consolidation of the trust s structure to occur on a tax-deferred basis. The SIFT Conversion Rules require that the exchange transaction or the dissolution transaction, as the case may be, be implemented prior to 2013. Alternative structures may also exist to enable a SIFT conversion after that date on a tax deferred basis.

As a result, we currently anticipate converting to a dividend paying corporation on or before January 1, 2011. We believe our current structure provides value for our Unitholders and there may not be any immediate incentive to make a structural change prior to this date. This will allow us to continue to carefully manage our tax pools for future use as a dividend paying corporation.

We believe there will be an ongoing demand from investors for strong yield investments, and that a dividend paying entity is the most appropriate for our current asset base.

At-the-Market Equity Distribution Program

On December 14, 2007, we entered into an equity distribution agreement which was subsequently amended on July 10, 2009 (the Distribution Agreement) with SG Americas Securities, LLC and FirstEnergy Capital Corp. (collectively, the Underwriters) which permits us to distribute up to 25,000,000 Trust Units from time to time through the Underwriters (the Equity Distribution Program). Sales of Trust Units, if any, pursuant to the Distribution Agreement are made in transactions that are deemed to be at-the-market distributions , including sales made directly on the NYSE or the TSX. The Trust Units are distributed at market prices prevailing at the time of sale and, as a result, prices may vary between purchasers and during the period of distribution. A total of 901,400 Trust Units were issued under the Equity Distribution Program during the year ended December 31, 2009. The net proceeds of the distribution of Trust Units were used to repay debt, for development capital expenditures and for general business purposes. Regulatory approval permitting the distribution under the Equity Distribution Program was allowed to expire in January 2010 and may be reinstated at any time.

Table of Contents

Historical Developments 2007 and 2008

On September 30, 2008, we closed the acquisition of Accrete Energy Inc. for total consideration of $120 million paid by the issuance of 4,973,325 Trust Units and the assumption of $22 million of Accrete s net liabilities. We acquired 1,900 boepd of production in the Harmattan gas field and 8.4 MMboe of P+P Company Interest reserves.

On August 21, 2008, we completed a U.S. $265 million private placement of 6.98 percent senior unsecured ten year notes to a group of U.S. investors, and a $15 million private placement of 6.61 percent senior unsecured ten year notes to a group of Canadian investors (together, the 2008 Senior Notes). Interest on these notes is payable semi-annually.

On June 13, 2008, we amended and renewed our Credit Facility. The Credit Facility is unsecured, covenant based and has a three-year term expiring June 15, 2011. We have the option to extend the Credit Facility each year, subject to the approval of the lenders, or repay the entire balance at the end of the three-year term. In 2009, we chose not to exercise this option. In addition, we have a demand operating line of credit for working capital purposes, the size of which was increased from $35 million to $50 million as part of the June 13, 2008 amendments. As at December 31, 2009, availability under these facilities was reduced by drawings of $71 million and by outstanding letters of credit in the amount of approximately $23.2 million.

During 2007, we disposed of certain non-core assets to high-grade our portfolio. Total proceeds from dispositions during 2007 was $476 million. These transactions resulted in a decrease of 21.7 MMboe Proved and 28.4 MMboe Proved Plus Probable Reserves.

On July 26, 2007, we completed a U.S. $400 million private placement of 6.35 percent senior unsecured ten year notes (the 2007 U.S. Senior Notes) to a group of U.S. investors. Interest on these notes is payable semi-annually.

On July 25, 2007, we filed a registration statement with the SEC to expand our distribution reinvestment and Trust Unit purchase plan (DRIP) to permit Unitholders resident in the United States to participate in the DRIP. The enhanced DRIP permits Unitholders to elect to reinvest their cash distributions in additional Trust Units at a five percent discount to the weighted average closing price of the Trust Units on the TSX for the 20 trading days immediately preceding the cash distribution date. In addition, pursuant to the DRIP, Unitholders may purchase additional Trust Units for cash of up to Cdn. $1,000 (U.S. $1,000) per month under the same terms.

On January 22, 2007, we closed the acquisition of entities that held certain properties from ConocoPhillips Canada for a purchase price of $1.0375 billion, prior to adjustments. This acquisition was funded through our December 8, 2006 equity offering of 24,265,000 Trust Units at a price of $19.00 per Trust Unit, which yielded total gross proceeds of $461,035,000, and from the proceeds of a $600,000,000 bridge credit facility, which has since been repaid in full. The acquisition added 64.7 MMboe of Total Proved Plus Probable Reserves and more than 375,000 acres of undeveloped lands. The acquired properties are high working interest and were a strategic fit to our existing asset base.

Trends

There are a number of business and economic factors which underlie trends in the oil and gas industry in western Canada that influence the future of our business.

Commodity prices have the most significant impact on our financial results, and have proven to be quite volatile since peak prices for oil and North American natural gas were reached in 2008. Oil prices have partially rebounded through the last half of 2009 while natural gas prices in North America have not experienced a similar recovery. At the same time, the increase in value of the Canadian dollar relative to the U.S. dollar has also reduced the reported value stated in Canadian dollars to Pengrowth of our oil and gas sales. Since our expenses are paid in Canadian dollars and commodity prices are generally US dollar denominated, the higher Canadian dollar has a negative impact on our cash flow. We have continued to hedge portions of our oil and natural gas production in order to partially insulate us from commodity price volatility. We have hedged in Canadian dollars to partially mitigate the impact of the rising Canadian dollar. We have adopted a cautious capital program in 2010 in order to maintain as much financial flexibility as possible in the face of continued commodity price uncertainty.

Our capital program for 2010 will continue to place a greater emphasis on value creation through our drilling programs. We will continue to spend capital to further our long term resource potential at Lindbergh and Horn River while looking for new areas where repeatable drilling programs can add production and reserves to complement our mature assets. With lower commodity prices and higher costs in western Canada, the Alberta and British Columbia governments introduced royalty incentive programs that include lower royalties for newly drilled wells and in Alberta a royalty credit to offset some of the drilling costs.

The deployment of newer drilling and completion technology, in particular multi-stage fractured horizontal wells, has changed the productivity and economic returns of wells in tighter geological formations. Mature assets in western Canada that were previously considered to be marginal now may have additional reserves, production and improved economics from the application of this newer technology. We also anticipate increasing our use of enhanced oil recovery technology such as hydrocarbon miscible floods, polymer injection and CO2 injection to increase the recoverable reserves from known reservoirs.

The credit and capital markets improved in 2009 allowing us to issue Trust Units for $285 million in net proceeds under a bought deal public offering of Trust Units and approximately $10 million under the Equity Distribution Program. Coupled with our intent to live within our cash flow, we are in a good position to acquire assets in western Canada. A significant number of producing properties in western Canada are expected to be sold in 2010 as larger oil and gas producers sell some of their conventional production and smaller gas-weighted producers may have difficulty funding full capital programs.

For additional information regarding our strategy in this business environment, see *Management s Discussion and Analysis Outlook* in our Annual Report for the year ended December 31, 2009.

Table of Contents

PENGROWTH OPERATIONAL INFORMATION

Principal Properties

The portfolio of properties acquired and held by us primarily includes relatively long life, oil and gas producing properties with established production profiles.

The following table summarizes our producing properties as of December 31, 2009 based on the GLJ Report using forecast prices and costs. We obtained the GLJ Report dated February 5, 2010 in respect of the oil and gas properties of Pengrowth effective December 31, 2009. The following table also contains our average daily production of oil, natural gas and NGLs for the year ended December 31, 2009.

Summary of Company Interest
at December 31, 2009(1)
(Forecast Prices and Costs)(2)

Field	P+P Reserves (Mboe)(4)	Remaining Reserve: Reserve Life (years)	Remaining Reserve: Life Index (years)	P+P Value Before Tax at 10% Discount ($MM)	2009 Oil Production (bblpd)	2009 Gas Production (MMcfpd)	2009 NGL Production (bblpd)	2009 Total Production (boepd)(4)
Light Oil Properties								
Judy Creek	34,085	50	13.4	758.3	6,221	5.3	1,899	8,998
Weyburn	21,811	48	22.1	405.1	2,653	0.0	0	2,652
Swan Hills	16,684	50	18.2	232.1	2,058	2.1	301	2,707
Carson Creek	15,749	44	14.4	264.3	2,150	4.3	247	3,110
Deer Mountain	6,000	47	20.4	105.8	576	0.1	73	672
Fenn Big Valley	5,799	50	9.6	90.5	741	4.9	78	1,639
Other(3)	30,859		10.4	619.4	6,768	6.2	386	8,190
Subtotal	**130,987**		**13.9**	**2,475.5**	**21,166**	**22.9**	**2,984**	**27,969**
Heavy Oil Properties								
Bodo	7,603	37	11.4	139.2	1,655	1.4	0	1,889
Jenner	6,756	24	6.2	202.1	2,900	2.6	20	3,353
Tangleflags	4,667	43	7.3	72.8	2,074	0.3	0	2,117
Other(3)	4,324		7.7	64.6	929	4.3	0	1,646
Subtotal	**23,350**		**7.9**	**478.7**	**7,559**	**8.6**	**20**	**9,005**
Conventional Gas Properties								
Olds	18,020	50	12.6	224.2	7	18.8	709	3,849
Harmattan	17,410	50	10.3	219.2	393	18.6	1,679	5,172
Carson Creek	7,920	19	4.5	198.8	40	6.6	1,126	2,262
Dunvegan	5,786	33	10.3	77.1	32	7.5	414	1,698
Quirk Creek	5,545	40	9.2	76.9	0	6.5	345	1,430
Kaybob	3,316	34	13.3	43.5	0	4.1	41	722

Blackstone	3,110	32	10.3	32.9	0	5.3	0	886
McLeod River	3,083	47	8.2	48.4	22	5.5	214	1,150
Other(3)	10,878		7.9	160.1	462	23.5	391	4,771
Subtotal	**75,069**		**9.0**	**1,081.1**	**956**	**96.4**	**4,919**	**21,939**
Shallow Gas Properties								
Twining/Three Hills Creek	11,779	50	10.5	194.6	389	12.4	342	2,794
Coal Bed Methane	9,066	39	12.6	105.9	0	12.4	9	2,069
Monogram	6,999	40	8.8	114.5	0	15.2	0	2,533
Jenner	6,313	32	9.8	74.7	21	10.1	10	1,707
Lethbridge	2,851	47	9.2	33.4	2	6.0	0	1,005
Other(3)	13,942		9.7	163.4	300	26.6	128	4,864
Subtotal	**50,950**		**10.1**	**686.6**	**713**	**82.6**	**489**	**14,971**
Offshore Gas Properties								
Sable Island	9,031	8	4.4	146.0	0	26.7	1,178	5,633
Subtotal	**9,031**		**4.4**	**146.0**	**0**	**26.7**	1,178	5,633
Oil Sands Properties								
Lindbergh	6,348	16		17.0	0	0.0	0	0

Table of Contents

Field	P+P Reserves (Mboe)[4]	Remaining Reserve Life (years)	Reserve Life Index (years)	P+P Value Before Tax at 10% Discount ($MM)	2009 Oil Production (bblpd)	2009 Gas Production (MMcfpd)	2009 NGL Production (bblpd)	2009 Total Production (boepd)[4]
Subtotal	**6,348**			**17.0**	**0**	**0.0**	0	0
Total	**295,734**		**10.6**	**4,884.9**	**30,393**	**237.2**	**9,590**	**79,518**

Notes:

(1) 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.

(2) Forecast prices are shown under the heading *Pricing Assumptions* .

(3) All Other includes our Working Interests and Royalty Interests in approximately 85 other properties.

(4) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

(5) We assess our asset portfolio by aggregating production from properties into the following categories: light oil; heavy oil; conventional gas; shallow gas and coal bed methane; offshore gas; and oil sands. Because all of the production from the properties are aggregated into one of these groups, as opposed to the actual commodities, the production and reserves by commodity reported elsewhere will be different than those reported above.

Light Oil Properties

Judy Creek

We have a 100 percent Working Interest in both the Judy Creek Beaverhill Lake Unit and the Judy Creek West Beaverhill Lake Unit (together referred to as Judy Creek). We also have a 54.4 percent Working Interest in the Judy Creek Gas Conservation Plant that services a number of other properties in the area including Swan Hills, Virginia Hills and South Swan Hills. Judy Creek is located approximately 200 kilometres northwest of Edmonton, Alberta and covers an area of approximately 38,300 acres. Judy Creek was discovered in 1959, placed on waterflood in 1962 and hydrocarbon miscible flood in 1985. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 34.1 MMboe. The Remaining Reserve Life is 50 years and the Reserve Life

Index is 13.4 years. Our Company Interest production for Judy Creek averaged 8,998 boepd in 2009.

2009 Development Activity

The 2009 development program included an oil producer drilled in the fourth quarter of 2008 in the northwest quadrant of A Pool that was completed and placed on production in January 2009. In December, three new miscible patterns in the southwest quadrant of the A Pool began solvent injection. Over the course of the year, nine acid fracture stimulations and three artificial-lift conversions added approximately 160 boepd.

2010 Development Activity

The 2010 capital program includes the development of a new miscible pattern. In addition, two directional oil producers will be drilled from existing suspended wellbores and one new vertical oil producer will be drilled. Follow-up oil well locations have been identified for execution pending results of the approved program. The ongoing program of well optimization will continue.

Carbon Dioxide (CO_2) Pilot

The intent of the Judy Creek CO_2 enhanced oil recovery pilot project is to evaluate the potential of CO_2 injection to increase oil recovery and to recover hydrocarbons left behind from the hydrocarbon miscible flood. The results will provide information to us to determine the feasibility of a commercial CO_2 injection. The injected fluid consists of trucked-in CO_2 and acid gas. The acid gas comes from the Judy Creek Conservation Plant and consists mainly of CO_2 and hydrogen sulfide (H_2S). CO_2 injection commenced in February of 2007 ended June 2009.

Table of Contents

Favorable response has been evident to date with both incremental oil and hydrocarbon gas and gas liquids from the hydrocarbon miscible flood being produced. To date, 1.2 Bcf of CO_2 has been injected into the 80 acre pilot pattern. This program has resulted in an additional 46 Mbbl of oil (approximately 2.3 percent of the original oil in place) and 190 MMcf of natural gas hydrocarbons being produced from the hydrocarbon miscible flood. Although CO_2 injection has ended, the increased production is expected to continue and monitoring will be maintained into 2010.

Weyburn Unit

The Weyburn Unit is located in southeastern Saskatchewan, Canada. Pengrowth holds a 9.76 percent non-operated Working Interest in the Unit. The Unit produces medium sour crude oil (25-34° API) from the Midale carbonate reservoir under waterflood and a CO_2 miscible flood enhanced oil recovery program. The field consists of approximately 700 production wells and 300 injection wells. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 21.8 MMboe. The Remaining Reserve Life is 48 years and the Reserve Life Index is 22.1 years. Our Company Interest production for Weyburn averaged 2,652 boepd in 2009.

2009 Development Activity

In 2009, drilling was limited to three horizontal CO_2 injectors. Efforts focused on the optimization of existing wells. CO_2 injection was held at 125 MMcfpd of source CO_2 plus approximately 123 MMcfpd of recycled CO_2, which is higher than previous years due to the addition of recycling compression in both 2008 and 2009.

2010 Development Activity

The 2010 capital program includes the drilling of two production wells, three CO_2 injectors and the start-up of five new CO_2 EOR patterns.

Swan Hills

The Swan Hills Unit is located near the Judy Creek field in north central Alberta. We hold a 24.01 percent non-operated Working Interest in the Swan Hills Unit No. 1. Light sour crude oil is produced from the Beaverhill Lake reservoir which has a waterflood and a hydrocarbon miscible flood EOR program. The remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 16.7 MMboe. The Remaining Reserve Life is 50 years and the Reserve Life Index is 18.2 years. Our Company Interest production for Swan Hills averaged 2,707 boepd in 2009.

2009 Development Activity

In 2009, four new oil wells were drilled in the east margin area of the Unit, three of which were on production at year end. Three new hydrocarbon miscible flood patterns were fully developed, which included the conversion of two oil wells to injectors. Solvent injection started in all three hyrdrocarbon miscible patterns in the second half of 2009. Two of the patterns were the first to target the platform of the reef. Pattern development began in 2008. In addition, eight oil wells were recompleted.

2010 Development Activity

No drilling is planned for 2010. Hydrocarbon miscible injection will continue in 2010. One existing pattern will be re-configured to flood a previously unswept reservoir. A 40 acre pattern that has been on water injection since 2008 will be converted to a hydrocarbon miscible pattern.

Carson Creek

Carson Creek is located 160 kilometres northwest of Edmonton, Alberta and is comprised of two Pengrowth-operated Units (one oil and one gas and condensate) which cover approximately 46,200 acres. The Carson Creek North Unit (oil), in which we have an 88.6 percent Working

Table of Contents

Interest, was discovered in 1958 and the current waterflood was initiated in 1964. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 15.7 MMboe. The Remaining Reserve Life is 44 years and the Reserve Life Index is 14.4 years. Our Company Interest production for the Carson Creek North Unit averaged 3,110 boepd in 2009.

2009 Development Activity

Our 2009 activities included ongoing geologic modeling and reservoir simulation, waterflood optimization and well workovers to improve production. Natural pool decline was entirely offset in 2009, resulting in a two percent increase in daily average rate over 2008.

2010 Development Activity

We anticipate taking advantage of regular well maintenance to enhance production from existing wells in the Carson Creek North Unit. Waterflood optimization, including several injector stimulations and a water injector conversion, are planned for 2010.

Deer Mountain Area

Deer Mountain is located 190 kilometres northwest of Edmonton, Alberta, and consists of both a Pengrowth-operated Unit, which covers approximately 6,400 acres, and four non-Unit wells. The 85.42 percent Working Interest in the Unit covers ten sections of land, and the non-Unit lands contribute an additional four sections of land with operated interests that range from 67 to 100 percent. A waterflood scheme has been operating in the Deer Mountain Unit since September 1968. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 6.0 MMboe. The Remaining Reserve Life is 47 years and the Reserve Life Index is 20.4 years. Our Company Interest production for Deer Mountain averaged 672 boepd in 2009.

2009 Development Activity

A waterflood optimization project was completed in December at Deer Mountain Unit No. 1. The response to the optimized waterflood is anticipated in the second half of 2010.

2010 Development Activity

We plan to drill two to four horizontal producers and will complete them with multi-stage fracturing. Two to three waterflood optimization workovers and acid fracture stimulation will also be implemented in 2010.

Fenn Big Valley

Fenn Big Valley is located 130 kilometres northeast of Calgary, Alberta. We have high working interests (mostly 100 percent) in several oil pools producing from the Nisku and Leduc formations. The Nisku production currently accounts for approximately 80 percent of the oil production at an average water cut of 97 percent. The field was placed on production in 1953 and has produced approximately 62 percent of the original oil in place under natural water drive. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 5.8 MMboe. The Remaining Reserve Life is 50 years and the Reserve Life Index is 9.6 years. Our Company Interest production for Fenn Big Valley averaged 1,639 boepd in 2009.

2009 Development Activity

Our 2009 activity included four Nisku oil recompletions and reactivations as well as five Belly River/Edmonton gas recompletions.

Table of Contents

2010 Development Activity

Our 2010 planned activities include a reactivation of a Nisku oil well and several recompletions of shallow gas wells.

Heavy Oil Properties

Bodo

The Bodo heavy oil property straddles the Alberta-Saskatchewan border near Township 35 and produces mainly 12° API oil from the McLaren formation and 15° API oil from the Lloydminster formation. We operate several batteries to treat oil, as well as a number of compressor stations to process solution and non-associated gas. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 7.6 MMboe. The Remaining Reserve Life is 37 years and the Reserve Life Index is 11.4 years. Our Company Interest production for Bodo averaged 1,889 boepd in 2009.

2009 Development Activity

We drilled one horizontal and one vertical well in the Cactus Lake Bakken pool. One horizontal well was drilled in the Bodo area as part of our successful polymer project. Injection wells were added in several areas, including Cactus Lake and East Bodo to expand the polymer area, and in South Bodo.

2010 Development Activity

A new ten well program is planned in the East Bodo area in 2010. The program will consist of seven producers and three injectors. We will convert producing wells to injection wells in East Bodo, Cactus and Cosine to improve ultimate oil recovery. The polymer flood is expected to be expanded to other portions of the pool.

Jenner

The Jenner oil property is located approximately 250 kilometres east of Calgary, Alberta. We have an average Working Interest of 94.5 percent in the north pool and an average Working Interest of 89.1 percent in the south pool. We operate all of the production within this property. Oil quality ranges from 14-20° API and is produced from Upper Mannville Sands. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 6.8 MMboe. The Remaining Reserve Life is 24 years and the Reserve Life Index is 6.2 years. Our Company Interest production for Jenner averaged 3,353 boepd in 2009.

2009 Development Activity

Our 2009 development activities included drilling two vertical oil wells and one gas well. In addition, water handling improvements were made and numerous production optimization projects were completed.

2010 Development Activity

The 2010 development activities will include the drilling of several oil wells as well as production optimization projects and further water handling improvements.

Tangleflags

Tangleflags is located in west central Saskatchewan, approximately 40 kilometres northeast of Lloydminster and produces 12° API oil mainly from the Lloydminster sands under thermal recovery process, with some cold production from other Mannville sands. We hold a 50 percent non-operating Working Interest. The thermal Tangleflags North EOR project commenced operation in the late 1980 s and a variety of well configurations have been tried. These include vertical injection with vertical production, vertical injection with horizontal production, and horizontal injection with horizontal production (i.e., steam assisted gravity drainage or SAGD). The remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 4.7 MMboe. The Remaining Reserve Life is 43 years and the Reserve Life Index is 7.3 years. Our Company Interest production for Tangleflags averaged 2,117 boepd in 2009.

2009 Development Activity

In 2009, three recompletions and five pump upgrades were completed.

2010 Development Activity

In 2010, fifteen recompletions are planned. No drilling is planned.

Conventional Gas Properties

Olds

The Olds property is our largest operated gas property, and is located 95 kilometres north of Calgary, Alberta. Our interests include 100 percent ownership in the Olds Gas Unit No. 1. In addition, we have a 75 percent average Working Interest in non-Unit reserves. The Olds Unit produces sour natural gas from the Wabamun Formation, with H_2S concentrations ranging from less than one to 35 percent. The non-Unit reserves are contained within formations from the Wabamun to the Edmonton group, and are predominantly sweet natural gas. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 18.0 MMboe. The Remaining Reserve Life is 50 years and the Reserve Life Index is 12.6 years. Our Company Interest production for Olds averaged 3,849 boepd in 2009.

We operate and own 100 percent of the sour gas processing plant at Olds, which processes both our production and third party volumes. Third party volumes represent approximately 30 percent of the total volumes processed.

2009 Development Activity

Many of the 2009 planned activities were delayed due to low commodity prices; however, one new Wabamun gas well was drilled and tied-in. A Pekisko well that was recompleted with multi-stage fracturing technology in late 2008 was brought back on-stream early in 2009 with a 250 percent production increase. A program to extinguish flare pilots in the field was implemented, resulting in fuel gas savings of 120 boepd.

2010 Development Activity

Development plans for 2010 include debottlenecking the gathering system with the installation of a new pipeline. In addition, recompletion of two to three Wabamun wells using multi-stage fracturing technology, a clean-out of a Wabamun well currently shut in, and the replacement of a corroded pipeline to another shut in well are planned.

Harmattan

The Harmattan gas field is located approximately 90 kilometres northwest of Calgary, Alberta. It is comprised of wells and pools in formations from the Cardium to the Wabamun, as well as two partner-operated Elkton Units. The production is predominantly sweet natural gas with Working Interests averaging 55 percent in the non-Unit lands and 25 percent in the Units. The Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 17.4 MMboe. The Remaining Reserve Life is 50 years and the Reserve Life Index is 10.3 years. Our Company Interest production for Harmattan averaged 5,172 boepd in 2009.

Table of Contents

2009 Development Activity

A successful Cardium well was drilled and field optimization resulted in production improvements of 115 boepd.

2010 Development Activity

Development plans for 2010 includes one to two Elkton infill drills, drilling a number of horizontal Cardium wells utilizing multiple stage fracturing technology and a recompletion of a Viking zone.

Carson Creek

Carson Creek is located 160 kilometers northwest of Edmonton, Alberta and is comprised of two Pengrowth-operated Units (one oil and one gas and condensate) which cover approximately 46,200 acres. The Carson Creek Beaverhill Lake Unit No. 1 (gas), in which we have a 95.1 percent Working Interest, was discovered in 1958. From 1962 to 1985, a lean gas cycling scheme to strip NGLs from the liquid-rich natural gas was operational. During this period, the lean gas was re-injected. Gas re-injection now only occurs during plant disruption. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 7.9 MMboe. The Remaining Reserve Life is 19 years and the Reserve Life Index is 4.5 years. Our Company Interest production for Carson Creek gas averaged 2,262 boepd in 2009.

We have a 95.1 percent Working Interest in the Carson Creek Gas plant, which processes the gas production.

2009 Development Activity

Development activity in 2009 consisted of drilling nine horizontal Swan Hills gas wells that proved the feasibility of horizontal stage fracturing technology in the newly delineated C pool. Capital cost savings were realized with each new well drilled.

2010 Development Activity

Continuation of the horizontal drilling program is planned for 2010. Six new horizontal drills have been budgeted for a program starting in the second half of the year.

Dunvegan

The partner operated Dunvegan gas field is located 430 kilometres northwest of Edmonton, Alberta in the Peace River area. We have a 10.37 percent Working Interest in the Dunvegan Gas Unit No. 1 and various interests in non-unit producing wells. The property contains over 200 producing wells and covers an area of approximately 52,600 acres. Approximately 95 percent of the Unit s identified natural gas reserves are contained in the Mississippian Middle Debolt formation. The balance is in the Upper Debolt formation, which is being annexed to the Unit. The remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 5.8 MMboe. The Remaining Reserve Life is 33 years and the Reserve Life Index is 10.3 years. Our Company Interest production for Dunvegan averaged 1,698 boepd in 2009.

2009 Development Activity

No drilling or completion activities occurred in 2009 due to low gas prices.

2010 Development Activity

Activity in 2010 will include ten new drilling locations focusing on the Middle Debolt zone. The addition of the Upper Debolt zone to the unit is expected to be finalized in 2010.

Table of Contents

Quirk Creek

The Quirk Creek asset is located approximately 50 kilometres southwest of Calgary, Alberta, and is comprised of several highly permeable pools contained within thrust sheets carrying Mississippian reservoirs. We hold a 68 percent Working Interest in four producing Rundle deep plate gas wells, a 31 percent Working Interest in ten producing Rundle upper plate gas wells, a 25 percent Working Interest in three producing gas wells in other zones and a 30.5 percent Working Interest in the Quirk Creek Gas Plant. Natural gas production averages nine percent sour natural gas, with associated liquids. Quirk Creek has been producing since the late 1960 s, but a new 68 percent Pengrowth Working Interest well was drilled in 2006. This was the first well drilled in 25 years and extended the structure s potential and accounts for the excess deliverability at Quirk Creek. The remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 5.5 MMboe. The Remaining Reserve Life is 40 years and the Reserve Life Index is 9.2 years. Our Company Interest production for Quirk Creek averaged 1,430 boepd in 2009, a marked increase over 2008 as a result of the resolution of a number of equipment and design problems.

2009 Development Activity

No drilling or other subsurface development work was performed in 2009. Well capability continues to exceed plant inlet capacity.

2010 Development Activity

No drilling or other subsurface development work is planned for 2010.

Kaybob

The Kaybob Notikewin Unit No. 1 is located approximately 240 kilometres northwest of Edmonton, Alberta. We hold a 98.88 percent Working Interest in the Unit. The Kaybob Notikewin Unit No. 1 produces natural gas and NGLs from the Notikewin formation. Initial production from the Unit began in 1962. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 3.3 MMboe. The Remaining Reserve Life is 34 years and the Reserve Life Index is 13.3 years. Our Company Interest production for Kaybob averaged 722 boepd in 2009.

2009 Development Activity

No drilling activity or well tie-ins took place in 2009.

2010 Development Activity

Two field compressor installations are planned to reduce producing pressures and increase production. One gas well reactivation is planned.

Blackstone

Blackstone is located approximately 180 kilometres northwest of Red Deer, Alberta. We hold a 50 percent Working Interest in one producing conventional gas well and a 23.9 percent Working Interest in a compressor facility. The subject well was drilled into the Blackstone Beaverhill Lake A Pool and was placed on production in January 2002. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 3.1 MMboe. The Remaining Reserve Life is 32 years and the Reserve Life Index is 10.3 years. Our Company Interest production for Blackstone averaged 886 boepd in 2009.

2009 Development Activity

There was no development activity on the Blackstone property in 2009.

Table of Contents

2010 Development Activity
No drilling is planned for 2010.
McLeod River
The McLeod River property is located approximately 110 kilometres west of Edmonton, Alberta. We hold various interests in 87 wells in the property ranging from 16.7 to 100 percent. Conventional gas is produced from the Rock Creek, Gething, Notikewin and Cardium formations. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 3.1 MMboe. The Remaining Reserve Life is 47 years and the Reserve Life Index is 8.2 years. Our Company Interest production for McLeod River averaged 1,150 boepd in 2009.
2009 Development Activity
Our 2009 development activity included two well recompletions and one well reactivation.
2010 Development Activity
The activities for 2010 will include drilling one well and recompleting five others.
Shallow Gas Properties
Twining/Three Hills Creek
The Twining/Three Hills Creek property is located 130 kilometres northeast of Calgary, Alberta. Although production is mainly gas, there is also oil production from this area. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 11.8 MMboe. The Remaining Reserve Life is 50 years and the Reserve Life Index is 10.5 years. Our Company Interest production for Twining/Three Hills Creek averaged 2,794 boepd in 2009.
2009 Development Activity
Development activity in 2009 included the drilling of one gas and three oil wells, one recompletion for oil and four recompletions for gas.
2010 Development Activity
Our 2010 development activities include drilling and recompleting Pekisko horizontal oil wells with multi-stage fracturing techniques. Five Mannville oil and gas recompletions are planned.
Coal Bed Methane (CBM)
Our CBM activity is focused in the Ghost Pine, Fenn Big Valley and Twining areas which are 100 to 160 kilometres northeast of Calgary, Alberta. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 9.1 MMboe. The Remaining Reserve Life is 39 years and the Reserve Life Index is 12.6 years. Our Company Interest CBM production averaged 2,069 boepd in 2009.
2009 Development Activity
We drilled four Horseshoe Canyon CBM wells and one Mannville CBM horizontal well. Partners drilled an additional 6.5 net wells.

2010 Development Activity
Plans for 2010 include drilling 35 Horseshoe Canyon CBM/Belly River gas wells and one Mannville CBM horizontal well.
Monogram Gas Unit
The Monogram Gas Unit is located approximately 225 kilometres southeast of Calgary, Alberta. We hold a 53.82 percent Working Interest in the partner-operated Unit. Gas production from the Unit is in the shallow Medicine Hat, Milk River and Second White Specks formations. The Monogram Unit was unitized June 1, 1975. To the end of 2009, 919 wells have been drilled. The remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 7.0 MMboe. The Remaining Reserve Life is 40 years and the Reserve Life Index is 8.8 years. Our Company Interest production for Monogram averaged 2,533 boepd in 2009.
2009 Development Activity
Our partner drilled 80 infill wells in the first quarter of 2009.
2010 Development Activity
There are no planned capital expenditures for 2010.
Jenner
The Jenner shallow gas property is located 250 kilometres east of Calgary, Alberta. Production from this property is primarily from the Milk River, Medicine Hat and Second White Specks formations within the Jenner, Atlee Buffalo and Atlee fields. We have an average Working Interest of 67.2 percent and operate the majority of the production. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 6.3 MMboe. The Remaining Reserve Life is 32 years and the Reserve Life Index is 9.8 years. Our Company Interest production for Jenner Shallow Gas averaged 1,707 boepd in 2009.
2009 Development Activity
Our 2009 development activities focused on gas well de-watering and two Belly River gas well recompletions.
2010 Development Activity
The 2010 development activities will focus on a shallow gas infill drilling program of approximately 70 wells for gas from the Milk River, Medicine Hat and Second White Specks Sands. In addition a number of wells will be re-completed.
Lethbridge
Our operations in the Lethbridge, Alberta area cover a large area and include operating over 250 wells, most of which are 100 percent Working Interest. All wells produce sweet gas from the Milk River, BFS (Barons) and Bow Island formations. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 2.9 MMboe. The Remaining Reserve Life is 47 years and the Reserve Life Index is 9.2 years. Our Company Interest production for Lethbridge averaged 1,005 boepd in 2009.
2009 Development Activity
During 2009, we performed 16 coiled tubing cleanouts and reactivated two wells.

Table of Contents

2010 Development Activity

The planned activities for 2010 include a continued well cleanout program.

Offshore Gas Properties

Sable Offshore Energy Project

The Sable Offshore Energy Project (SOEP) is located 225 kilometres off the east coast of Nova Scotia and consists of several natural gas fields and five producing platforms. We have an 8.4 percent Working Interest in SOEP. Raw gas is delivered to an onshore gas plant facility at Goldboro where the liquids are extracted and sent to the Point Tupper fractionation plant for processing. Sales gas is transported to market via the Maritimes and Northeast Pipeline. Propane and butane are shipped by both truck and rail and condensate is transported by tanker ship from the platform. SOEP has been producing since late 1999.

Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2009 are estimated to be 9.0 MMboe. The Remaining Reserve Life is 8 years and the Reserve Life Index is 4.4 years. Our Company Interest production for SOEP averaged 5,633 boepd in 2009.

2009 Development Activity

The 2009 activities at SOEP included the successful drilling of a fourth well in the Alma field. The well was brought on production in October. A maintenance campaign was conducted in August, during which expanded living quarters were installed on the Thebaud platform and vessel inspections and repairs were completed.

2010 Development Activity

Development activities in 2010 are expected to consist of a series of workovers for wells in the Venture field, and an expansion of the propane truck loading facilities at the Point Tupper fractionation plant. The benefits of developing small gas discoveries (Significant Discovery Licenses) close to the Sable project will be investigated.

Oil Sands Properties

Lindbergh

The Lindbergh oil sands property is located approximately 420 kilometres northeast of Calgary and 65 kilometres southwest of Cold Lake. We hold a 100 percent Working Interest in this oil sands asset where oil quality averages 11° API from the Lloydminster oil sands.

Company Interest Total Proved plus Probable Reserves at December 31, 2009 are estimated to be 6.3 MMboe. See also *Lindbergh Oil Sands Contingent Resources* .

2009 Development Activity

The planned drilling program was executed early in 2009 with the completion of two delineation and two observation wells. At mid year, lease continuation applications were made and accepted by Alberta Energy for the expiring portions of the oilsands leases.

2010 Development Activity

The 2010 program includes delineation drilling and other development work to further confirm resource estimates as well as detailed engineering and procurement in preparation for development of the pilot.

Statement of Oil and Gas Reserves and Reserves Data

Disclosure of Reserves Data

The information in this section is based upon an evaluation by GLJ, prepared in accordance with NI 51-101, with an effective date of December 31, 2009 contained in the GLJ Report dated February 5, 2010, with the exception of information relating to income tax and the after tax future net revenues associated with our reserves, which we determined. The effective date of the information in this section is December 31, 2009 and the preparation date is January 15, 2010 when the final information was provided. The information in this section summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using GLJ s forecast prices and costs and constant prices and costs. We engaged GLJ to provide an independent evaluation of Proved Reserves and Total Proved Plus Probable Reserves and no attempt was made to evaluate Possible Reserves in the conventional properties. It is our practice to obtain an engineering report evaluating all of our Proved Reserves and Probable Reserves as at December 31 of each year. Only in respect of the Lindbergh oil sands property did GLJ evaluate Possible Reserves and Contingent Resources. All of our reserves are in Canada in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia.

The following tables set forth certain information relating to our oil and natural gas reserves and the net present value of the estimated future net revenue associated with such reserves as at December 31, 2009 contained in the GLJ Report dated February 5, 2010. These tables summarize the data contained in the GLJ Report, and, as a result, may contain slightly different numbers than the GLJ Report due to rounding. Columns may not add due to rounding.

For the purposes of this Annual Information Form, the Probable Reserves reported for the Lindbergh oil sands property in the GLJ Report are included with the Heavy Oil reserves. See *Lindbergh Oil Sands Reserves and Contingent Resources* .

Our future net revenues associated with the production and reserves contained in this Annual Information Form reflect the royalty programs in-place on December 31, 2009. Approximately 74 percent of our reserves are on Alberta Crown land where the Province announced in 2009 a New Well Royalty Reduction (NWRR) program that provides a royalty credit equal to $200 per meter drilled and a five percent royalty for the first twelve months of production, not exceeding 50,000 barrels of oil or 500 million cubic feet of gas. This NWRR program applies to wells that began drilling (spud) on or after April 1, 2009 and before March 31, 2011. There are two additional royalty programs which the Province has established: the New Royalty Framework and Transitional Royalties. The Transitional Royalties, which may be elected, applies to wells drilled after November 18, 2008 and to production through December 31, 2013. In the GLJ Report, no election for the Transitional Royalties was assumed as there was no economic advantage to make such an election.

Approximately four percent of our reserves are on British Columbia Crown Lands where the Province announced in August 2009 an oil and gas stimulus package. The stimulus package included a two percent royalty rate for all wells drilled from September 2009 through June 2010.

The information set forth below is derived from the GLJ Report, which has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook and the reserves definitions contained in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook. The GLJ Report incorporates estimates of future well abandonment obligations but does not include estimates of remediation costs. **The GLJ forecasts of future net revenue are stated prior to any provision for income taxes, interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net revenue shown below is representative of the fair market value of the properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.**

Table of Contents

We determined the future net revenue and present value of future net revenue after income taxes after taking into account the impact of the SIFT Legislation. See *Certain Canadian Federal Income Tax Considerations Taxation of the Trust SIFT Legislation*. Our estimate of income tax in the foregoing analysis makes use of the following assumptions:

- SIFT tax starting January 2011 at 27.06 percent (and 25.56 percent in 2012 and thereafter). The SIFT tax is based on the provincial allocation from the Corporation s December 31, 2008 tax return;
- Annual general and administration expenses at the current level;
- Interest expense at the current level;
- Inclusion of tax pools and deductions at the trust level as well as at the operating entity level (total tax pools of $2.9 billion);
- Royalties paid to the Trust after allowance for capital expenses contemplated by the GLJ Report;
- Distributions by the Trust to the Unitholders in an amount equal to the cash received by the Trust; and
- Any such other additional deductions and adjustments as is and would be consistent with the manner in which we file and would file future tax returns. See *Canadian Income Tax Considerations*.

The net revenues estimated in the GLJ Report represent estimates of the revenues from oil and gas sales from our petroleum and natural gas properties together with an estimate of processing revenues less royalties (net of incentives), mineral taxes, field operating expenses and capital obligations. These net revenues are not the same as cash flows from operating activities reported by the Trust in its statement of cash flows. The GLJ Report does not estimate general and administrative expenses and interest.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached to this Annual Information Form as Appendices A and B, respectively.

Table of Contents

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves
as of December 31, 2009
(Forecast Prices and Costs) (1)

	Light and Medium Oil			Heavy Oil(2)			Natural Gas Liquids		
Reserves Category	**Company Interest** (Mbbl)	**Gross Interest** (Mbbl)	**Net Interest** (Mbbl)	**Company Interest** (Mbbl)	**Gross Interest** (Mbbl)	**Net Interest** (Mbbl)	**Company Interest** (Mbbl)	**Gross Interest** (Mbbl)	**Net Interest** (Mbbl)
Proved Reserves									
Proved Developed Producing	65,640	65,504	52,047	14,370	14,362	12,750	19,253	19,165	14,026
Proved Developed Non- Producing	804	804	556	139	139	127	1,030	1,029	769
Proved Undeveloped	16,358	16,351	12,391	1,846	1,846	1,533	1,190	1,190	795
Total Proved Reserves	82,803	82,659	64,995	16,355	16,347	14,410	21,473	21,384	15,591
Probable Reserves	29,446	29,400	22,476	11,370	11,367	9,976	8,114	8,091	5,892
Total Proved Plus Probable Reserves	112,249	112,059	87,471	27,724	27,713	24,386	29,587	29,475	21,482

	Natural Gas			Coal Bed Methane			Total Oil Equivalent Basis(3)		
RESERVES CATEGORY	**Company Interest** (MMcf)	**Gross Interest** (MMcf)	**Net Interest** (MMcf)	**Company Interest** (MMcf)	**Gross Interest** (MMcf)	**Net Interest** (MMcf)	**Company Interest** (Mboe) (3)	**Gross Interest** (Mboe) (3)	**Net Interest** (Mboe) (3)
Proved Reserves									
Proved Developed Producing	484,396	481,215	409,311	23,034	21,906	21,635	183,835	182,885	150,648
Proved Developed Non-Producing	18,490	18,322	14,460				5,055	5,025	3,862
Proved Undeveloped	30,360	30,359	26,463	19,263	19,184	16,325	27,665	27,644	21,851
Total Proved Reserves	**533,246**	**529,897**	**450,234**	**42,297**	**41,090**	**37,960**	**216,554**	**215,554**	**176,361**
Probable Reserves	170,204	169,277	140,778	11,293	11,037	10,226	79,180	78,911	63,511
Total Proved Plus Probable Reserves	**703,449**	**699,175**	**591,013**	**53,590**	**52,127**	**48,186**	**295,734**	**294,464**	**239,872**

Notes:

(1) Forecast prices are shown under the heading

Pricing Assumptions .

(2) Includes 6,348 Mbbl of Company Interest heavy oil Probable Reserves for the Lindbergh oil sands property in the GLJ Report.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

Table of Contents

Summary of Net Present Value
of Future Net Revenue
as of December 31, 2009
Before and After Income Taxes
(Forecast Prices and Costs)(1)

	Before Income Taxes Discounted at (%/Year)					Unit Value Before Income Tax Discounted at 10%/Year(2)	
Reserves Category	**0%** ($MM)	**5%** ($MM)	**10%** ($MM)	**15%** ($MM)	**20%** ($MM)	$/boe	$/Mcfe
Proved Reserves							
Proved Developed Producing	5,793	4,301	3,442	2,888	2,502	22.85	3.81
Proved Developed Non-Producing	162	118	93	77	66	24.11	4.02
Proved Undeveloped	1,046	571	335	203	124	15.32	2.55
Total Proved Reserves	**7,002**	**4,989**	**3,870**	**3,168**	**2,691**	**21.94**	**3.66**
Probable Reserves	3,141	1,641	1,015	696	510	15.99	2.66
Total Proved Plus Probable Reserves	**10,143**	**6,630**	**4,885**	**3,865**	**3,202**	**20.36**	**3.39**

	After Income Taxes Discounted at (%/Year)(3)				
Reserves Category	**0%** ($MM)	**5%** ($MM)	**10%** ($MM)	**15%** ($MM)	**20%** ($MM)
Proved Reserves					
Proved Developed Producing	5,189	3,840	3,079	2,594	2,260
Proved Developed Non-Producing	103	76	60	51	44
Proved Undeveloped	674	337	184	101	52
Total Proved Reserves	**5,966**	**4,253**	**3,323**	**2,746**	**2,356**
Probable Reserves	2,361	1,194	733	505	372
Total Proved Plus Probable Reserves	**8,327**	**5,447**	**4,056**	**3,251**	**2,728**

Notes:

(1) Forecast prices are shown under the heading *Pricing Assumptions* .

(2) Net present value of future

net revenue per reserve unit values are based on our net reserves.

(3) After tax figures were calculated assuming we would continue to be organized as a trust and would be subject to the SIFT Legislation. See *Statement of Oil and Gas Reserves and Reserves Data Disclosure of Reserves Data* for a description of the assumptions made in calculating the after tax figures.

Table of Contents

Additional Information Concerning Future Net Revenue
(undiscounted)
as of December 31, 2009
(Forecast Prices and Costs)[1]

Reserves Category	Revenue ($MM)	Royalties[2] ($MM)	Operating Costs ($MM)	Capital Development Costs ($MM)	Abandonment Costs[3] ($MM)	Future Net Revenue Before Income Taxes ($MM)	Income Tax ($MM)	Future Net Revenue After Income Taxes ($MM)
Proved Reserves	15,658	3,031	4,853	537	235	7,002	1,035	5,967
Total Proved Plus Probable Reserves	22,388	4,426	6,670	887	262	10,143	1,816	8,327

Notes:

(1) Forecast prices are shown under the heading *Pricing Assumptions* .

(2) Crown royalties payable to the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia and any freehold and over-riding royalties payable. This includes the impact of the New Royalty Framework implemented by the Government of Alberta on January 1, 2009, the optional Transitional Royalty and any drilling incentive

programs currently in effect.

(3) Includes the cost of well abandonments and abandonment of Sable Island facilities and subsea pipelines, but does not include abandonment costs for other facilities or any surface reclamation costs. See *Pengrowth Operational Information Additional Information Concerning Abandonment & Reclamation Costs*.

Net Present Value of Future Net Revenue
By Production Group
as of December 31, 2009
(Forecast Prices and Costs)[1]

Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes** (discounted at 10%/yr) ($MM)	**Unit Value[4]** ($/boe)	($/Mcfe)
Total Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)[2]	2,015	25.86	4.31
	Heavy Oil (including solution gas and other by-products)[2]	395	24.99	4.16
	Natural Gas (including by-products but excluding solution gas from oil wells)[3]	1,374	18.00	3.00

	Coal Bed Methane	87	13.74	2.29
	Total	**3,870**	**21.94**	**3.66**
Total Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)(2)	2,510	24.11	4.02
	Heavy Oil (including solution gas and other by-products)(2)	506	19.21	3.20
	Natural Gas (including by-products but excluding solution gas from oil wells)(3)	1,759	17.36	2.89
	Coal Bed Methane	109	13.59	2.26
	Total	**4,885**	**20.36**	**3.39**

Notes:

(1) Forecast prices are shown under the heading *Pricing Assumptions* .

(2) NGL s associated with the production of solution gas are included as a by-product.

(3) NGL s associated with the production of natural gas are included as a by-product.

(4) Net present value of future net revenue per reserve unit values are based on our net reserves.

Table of Contents

Reserves Data (Constant Prices and Costs)

Summary of Oil And Gas Reserves
as of December 31, 2009
(Constant Prices and Costs)[1]

	Light and Medium Oil			Heavy Oil[2]			Natural Gas Liquids		
Reserves Category	**Company Interest** (Mbbl)	**Gross Interest** (Mbbl)	**Net Interest** (Mbbl)	**Company Interest** (Mbbl)	**Gross Interest** (Mbbl)	**Net Interest** (Mbbl)	**Company Interest** (Mbbl)	**Gross Interest** (Mbbl)	**Net Interest** (Mbbl)
Proved Reserves									
Proved Developed Producing	62,736	62,613	54,860	13,951	13,944	12,731	17,220	17,137	12,592
Proved Developed Non-Producing	783	783	573	139	139	132	1,048	1,047	795
Proved Undeveloped	16,080	16,072	13,543	1,841	1,841	1,634	992	992	665
Total Proved Reserves	**79,599**	**79,467**	**68,976**	**15,931**	**15,924**	**14,498**	**19,260**	**19,175**	**14,052**
Probable Reserves	29,807	29,764	25,625	11,269	11,266	10,609	8,532	8,511	6,234
Total Proved Plus Probable Reserves	**109,405**	**109,231**	**94,601**	**27,200**	**27,190**	**25,106**	**27,792**	**27,686**	**20,286**

	Natural Gas			Coal Bed Methane			Total Oil Equivalent Basis[3]		
Reserves Category	**Company Interest** (MMcf)	**Gross Interest** (MMcf)	**Net Interest** (MMcf)	**Company Interest** (MMcf)	**Gross Interest** (MMcf)	**Net Interest** (MMcf)	**Company Interest** (Mboe) [3]	**Gross Interest** (Mboe) [3]	**Net Interest** (Mboe) [3]
Proved Reserves									
Proved Developed Producing	413,139	410,444	361,187	20,546	19,464	19,336	166,188	165,345	143,603
Proved Developed Non-Producing	16,666	16,528	13,505				4,748	4,723	3,752
Proved Undeveloped	11,896	11,894	10,538	12,780	12,731	10,810	23,025	23,008	19,400
Total Proved Reserves	**441,701**	**438,866**	**385,230**	**33,326**	**32,195**	**30,146**	**193,960**	**193,077**	**166,755**
Probable Reserves	167,893	167,103	145,333	10,395	10,160	9,484	79,323	79,085	68,271
	609,594	**605,970**	**530,563**	**43,720**	**42,355**	**39,630**	**273,283**	**272,162**	**235,025**

Total Proved Plus Probable Reserves

Notes:

(1) Constant prices are shown under the heading *Pricing Assumptions* .

(2) Includes 6,348 Mbbl of Company Interest heavy oil Probable Reserves for the Lindbergh oil sands property in the GLJ Report.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

Table of Contents

Summary of Net Present Value of Future Net Revenue as of December 31, 2009 Before and After Income Tax (Constant Prices and Costs)(1)

	Before Income Taxes Discounted At (%/Year)					Unit Value Before Income Tax Discounted At 10%/Year(2)	
Reserves Category	**0%** ($MM)	**5%** ($MM)	**10%** ($MM)	**15%** ($MM)	**20%** ($MM)	$/boe	$/Mcfe
Proved Reserves							
Proved Developed Producing	2,796	2,204	1,835	1,581	1,397	12.78	2.13
Proved Developed Non-Producing	75	58	47	40	35	12.65	2.11
Proved Undeveloped	526	276	150	79	37	7.71	1.29
Total Proved Reserves	**3,397**	**2,538**	**2,032**	**1,701**	**1,469**	**12.18**	**2.03**
Probable Reserves	1,413	775	484	328	234	7.09	1.18
Total Proved Plus Probable Reserves	**4,809**	**3,313**	**2,516**	**2,029**	**1,703**	**10.70**	**1.78**

	After Income Taxes Discounted At (%/Year)(3)				
Reserves Category	**0%** ($MM)	**5%** ($MM)	**10%** ($MM)	**15%** ($MM)	**20%** ($MM)
Proved Reserves					
Proved Developed Producing	2,725	2,143	1,780	1,533	1,353
Proved Developed Non-Producing	50	39	32	27	24
Proved Undeveloped	522	271	147	78	36
Total Proved Reserves	**3,297**	**2,453**	**1,959**	**1,638**	**1,413**
Probable Reserves	1,209	642	394	265	190
Total Proved Plus Probable Reserves	**4,506**	**3,095**	**2,353**	**1,903**	**1,603**

Notes:

(1) Constant prices are shown under the heading *Pricing Assumptions*.

(2) Net present value of future net revenue per reserve unit values are based on our net reserves.

(3) After tax figures were calculated assuming we would continue to be organized as a trust and would be subject to the SIFT Legislation. See *Statement of Oil and Gas Reserves and Reserves Data Disclosure of Reserves Data* for a description of the assumptions made in calculating the after tax figures.

Table of Contents

Additional Information Concerning Future Net Revenue (undiscounted) as of December 31, 2009 (Constant Prices and Costs)[1]

Reserves Category	Revenue ($MM)	Royalties[2] ($MM)	Operating Costs ($MM)	Capital Development Costs ($MM)	Abandonment Costs[3] ($MM)	Future Net Revenue Before Income Taxes ($MM)	Income Tax ($MM)	Future net Revenue After Income Taxes ($MM)
Proved Reserves	8,559	1,184	3,418	392	167	3,397	100	3,297
Total Proved Plus Probable Reserves	12,060	1,655	4,693	727	176	4,809	303	4,506

Notes:

(1) Constant prices are shown under the heading *Pricing Assumptions* .

(2) Crown royalties payable to the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia and any freehold and over-riding royalties payable. This includes the impact of the New Royalty Framework implemented by the Government of Alberta on January 1, 2009, the optional Transitional

Royalty and any drilling incentive programs still in effect.

(3) Includes the cost of well abandonments and abandonment of Sable Island facilities and subsea pipelines, but does not include abandonment costs for other facilities or any surface reclamation costs. See *Pengrowth Operational Information Additional Information Concerning Abandonment & Reclamation Costs* .

Net Present Value of Future Net Revenue
By Production Group
as of December 31, 2009
(Constant Prices and Costs)[1]

Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes** (discounted at 10%/yr) ($MM)	**Unit Value[4]** ($/Boe)	($/Mcfe)
Total Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)[2]	1,175	14.41	2.40
	Heavy Oil (including solution gas and other by-products)[2]	266	16.80	2.80
		566	8.79	1.46

	Natural Gas (including by-products but excluding solution gas from oil wells)[3]			
	Coal Bed Methane	25	4.97	0.83
	Total	**2,032**	**12.18**	**2.03**
Total Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)[2]	1,457	13.09	2.18
	Heavy Oil (including solution gas and other by-products)[2]	310	11.48	1.91
	Natural Gas (including by-products but excluding solution gas from oil wells)[3]	717	7.95	1.33
	Coal Bed Methane	32	4.81	0.80
	Total	**2,516**	**10.70**	**1.78**

Notes:

(1) Constant prices are shown under the heading *Pricing Assumptions* .

(2) NGL s associated with the production of solution gas are included as a by-product.

(3) NGL s associated with the production of natural gas are included as a by-product.

(4) Net present value of future net revenue per reserve unit values are based on our net reserves.

Table of Contents

Pricing Assumptions

Forecast Prices used in Estimates

The forecast price and cost assumptions assume the continuance of current laws and regulations and changes in wellhead selling prices, and take into account inflation with respect to future operating and capital costs. The forecast prices are provided in the table below and reflect GLJ s January 1, 2010 price forecast as referred to in the GLJ Report.

	Oil				**Natural Gas**	**Natural Gas Liquids[1]**				
Year	**WTI Cushing Oklahoma** ($US/bbl)	**Edmonton Par Price 40°API** ($Cdn/bbl)	**Cromer Medium 29.3°API** ($Cdn/bbl)	**Hardisty Heavy 12° API** ($Cdn/bbl)	**AECO Gas Price** ($Cdn/MMBtu)	**Propane** ($Cdn/bbl)	**Butane** ($Cdn/bbl)	**Pentanes Plus** ($Cdn/bbl)	**Inflation Rates[2]** (%/Year)	**Exchange Rate[3]** ($US/Cdn)
2009[4]	61.56	66.43	63.19	54.36	4.20	37.58	47.31	67.99		
2010	80.00	83.26	76.60	64.99	5.96	52.46	64.11	84.93	2.0	0.95
2011	83.00	86.42	78.64	65.24	6.79	54.45	66.54	88.15	2.0	0.95
2012	86.00	89.58	80.62	65.33	6.89	56.43	68.98	91.37	2.0	0.95
2013	89.00	92.74	82.54	65.26	6.95	58.42	71.41	94.59	2.0	0.95
2014	92.00	95.90	85.35	67.52	7.05	60.42	73.84	97.82	2.0	0.95
2015	93.84	97.84	87.07	68.90	7.16	61.64	75.33	99.79	2.0	0.95
2016	95.72	99.81	88.83	70.32	7.42	62.88	76.85	101.81	2.0	0.95
2017	97.64	101.83	90.63	71.76	7.95	64.15	78.41	103.86	2.0	0.95
2018	99.59	103.88	92.46	73.22	8.52	65.45	79.99	105.96	2.0	0.95
2019	101.58	105.98	94.32	74.72	8.69	66.77	81.60	108.10	2.0	0.95
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.95

Notes:

(1) FOB Edmonton.

(2) Inflation rates for forecasting prices and costs.

(3) The exchange rates used to generate the benchmark reference prices in this table.

(4) Actual weighted average historical prices for 2009.

Constant Prices used in Estimates

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the GLJ Report. Product prices were determined from the actual prices on the first day of each month during 2009 and were not escalated. In addition to the product prices, operating and capital costs have no inflationary increase. The constant prices are as follows:

Oil	**Natural Gas**	**Natural Gas Liquids[1]**	**Exchange**

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	AECO Gas Price ($Cdn/MMBtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	Inflation Rate (%/Year)	Rate[(2)] ($US/Cdn)
2010	61.04	63.59	59.56	51.80	3.84	36.87	46.87	66.67	0.0%	0.8728

Notes:

(1) FOB Edmonton.

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

Table of Contents

Reserves Reconciliation

The following tables provide a reconciliation of our gross reserves of crude oil, natural gas and NGLs for the year ended December 31, 2009, presented using forecast prices and costs. All reserves are located in Canada.

Reserves Reconciliation
By Principal Product Type
(Forecast Prices and Costs)

	Light and Medium Oil			**Heavy Oil**			**Natural Gas Liquids**		
	Gross Proved (Mbbl)	**Gross Probable** (Mbbl)	**Gross Proved Plus Probable** (Mbbl)	**Gross Proved** (Mbbl)	**Gross Probable** (Mbbl)	**Gross Proved Plus Probable** (Mbbl)	**Gross Proved** (Mbbl)	**Gross Probable** (Mbbl)	**Gross Proved Plus Probable** (Mbbl)
December 31, 2008	**90,261**	**30,846**	**121,107**	**16,268**	**11,448**	**27,716**	**23,436**	**8,873**	**32,309**
Extensions	252	452	704	139	(71)	68	934	289	1,223
Infill Drilling	137	128	265				656	(2)	655
Improved Recovery	1,152	(526)	626	225	63	288	7	17	24
Technical Revisions	(1,570)	(1,828)	(3,398)	2,350	(114)	2,236	(29)	(1,045)	(1,075)
Discoveries	100	200	300	129	43	172			
Acquisitions	877	206	1,083				214	47	260
Dispositions	(245)	(77)	(323)	(7)	(2)	(9)	(353)	(88)	(441)
Economic Factors									
Production	(8,305)		(8,305)	(2,756)		(2,756)	(3,480)		(3,480)
December 31, 2009	**82,659**	**29,400**	**112,059**	**16,347**	**11,367**	**27,713**	**21,384**	**8,091**	**29,475**

	Natural Gas			**Coal Bed Methane**			**Total Oil Equivalent Basis**		
	Gross Proved (MMcf)	**Gross Probable** (MMcf)	**Gross Proved Plus Probable** (MMcf)	**Gross Proved** (MMcf)	**Gross Probable** (MMcf)	**Gross Proved Plus Probable** (MMcf)	**Gross Proved** (Mboe) [1]	**Gross Probable** (Mboe) [1]	**Gross Proved Plus Probable** (Mboe) [1]
December 31, 2008	591,413	205,163	796,576	33,019	14,960	47,979	234,036	87,855	321,891
Extensions	6,467	2,382	8,849	729	145	873	2,523	1,092	3,615
Infill Drilling	3,923	2,021	5,943	7,642	1,422	9,064	2,721	700	3,421
Improved Recovery	843	901	1,743	451	(451)		1,600	(371)	1,229
	16,212	(38,680)	(22,468)	3,652	(5,038)	(1,386)	4,062	(10,275)	(6,213)

Technical Revisions									
Discoveries							229	243	472
Acquisitions	1,432	306	1,738				1,329	304	1,633
Dispositions	(9,615)	(2,815)	(12,430)				(2,208)	(637)	(2,845)
Economic Factors									
Production	(80,777)		(80,777)	(4,403)		(4,403)	(28,738)		(28,738)
December 31, 2009	**529,897**	**169,278**	**699,175**	**41,090**	**11,037**	**52,127**	**215,554**	**78,911**	**294,464**

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

Table of Contents

At December 31 2009, Company Interest Total Proved Plus Probable Reserves at forecast prices and costs were 295.7 MMboe as compared to 323.5 MMboe reported at year end 2008 and 319.9 MMboe reported at year end 2007. The following additional GLJ reserves reconciliation is presented for year end December 31, 2009.

Company Interest Reserves Reconciliation
on Total Oil Equivalent Basis
(Forecast Prices and Costs)

	Proved Producing Reserves (Mboe)[1]	**Proved Reserves** (Mboe) [1]	**Proved Plus Probable Reserves** (Mboe) [1]
December 31, 2008	**200,580**	**235,224**	**323,463**
Extensions	2,052	2,532	3,617
Infill Drilling	2,763	2,721	3,425
Improved Recovery	1,558	1,620	1,259
Technical Revisions	6,758	4,191	(6,194)
Discoveries	129	229	472
Acquisitions	1,287	1,329	1,633
Dispositions	(2,266)	(2,267)	(2,916)
Economic Factors			
Production	(29,025)	(29,025)	(29,025)
December 31, 2009	**183,835**	**216,554**	**295,734**

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

Significant factors bearing on the reserves reconciliation were as follows:

Certain probable undeveloped reserves were removed as a result of changing corporate strategy regarding future capital deployment. Also, various performance related revisions were made to previous estimates. Together this resulted in a net negative change in Total Proved Plus Probable Reserves. The largest revisions occurred at Sable Island (+1,625 Mboe), Carson Creek (+1,184 Mboe), Jenner (-948 Mboe), Judy Creek (-1,771 Mboe) and Olds (-6,434 Mboe). The majority of the strategy related reserve changes were made at Olds where management does not foresee drilling a large number of gas wells.

Reserve additions from drilling activity, improved recovery and technical revisions replaced 2009 production by 39 percent and nine percent for Total Proved and Proved Plus Probable Reserves, respectively. Based on all changes, including acquisitions and dispositions, reserve replacement was 36 percent and four percent for Total Proved and Proved Plus Probable Reserves, respectively. Pengrowth reinvested 38 percent of operating cash flow into capital projects.

New reserve additions for development activity during 2009 amounted to 8.8 MMboe of Total Proved Plus Probable Reserves. Most significant were infill drilling and extensions at Carson Creek and in the Twining CBM area and improved recovery and infill drilling adds at Weyburn. Reserve increases in the Proved Producing category also resulted from reclassification of Proved or Probable Undeveloped Reserves to producing primarily for infill drilling and drilling extensions at Carson Creek, Weyburn, Sable Island and Monogram.

The net decrease of 1.3 MMboe to Proved Plus Probable Reserves from acquisitions and dispositions was due to the sale of some minor non-core properties mainly at Niton, Karr and Pine Creek, offset by some small strategic asset acquisitions at House Mountain and Carson Creek.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved and Probable Undeveloped Reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, Undeveloped Reserves are scheduled to be developed within the next two to three years. Much of the remaining

Table of Contents

capital scheduled beyond this period is related to the Weyburn, Judy Creek and Swan Hills enhanced oil recovery projects, which have staged development plans.

Company Gross Reserves First Attributed by Year[1]

Proved Undeveloped Reserves

	Light & Medium Oil (Mbbl)		**Heavy Oil** (Mbbl)		**Natural Gas** (MMcf)		**Coal Bed Methane** (MMcf)		**Natural Gas Liquids** (Mbbl)		**Total Oil Equivalent** (Mboe)[2]	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
Prior	20,521	36,107	1,994	3,590	45,093	73,203	3,955	3,955	1,509	2,527	32,198	55,084
2007	1,932	18,985	342	2,194	20,905	50,224	11,356	13,911	398	1,361	8,049	33,229
2008	1,000	17,029	382	1,676	3,513	48,311	1,858	10,372	125	1,120	2,402	29,606
2009	1,347	16,351	130	1,846	2,778	30,359	10,140	19,184	209	1,190	3,840	27,644

Probable Undeveloped Reserves

	Light & Medium Oil (Mbbl)		**Heavy Oil** (Mbbl)		**Natural Gas** (MMcf)		**Coal Bed Methane** (MMcf)		**Natural Gas Liquids** (Mbbl)		**Total Oil Equivalent** (Mboe)[2]	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
Prior	10,681	19,454	2,013	3,092	36,315	73,467	4,306	4,306	1,593	3,213	21,058	38,721
2007	3,065	13,497	726	2,269	25,386	64,986	8,170	10,155	670	2,716	10,054	31,006
2008	1,805	12,372	6,997	7,857	17,686	68,822	4,514	7,948	782	3,478	13,329	36,502
2009	1,565	11,514	68	7,853	9,450	37,134	2,177	5,178	934	2,510	4,505	28,929

Notes:

(1) First Attributed refers to reserves first attributed at year-end of the corresponding fiscal year.

(2) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

Proved Undeveloped Reserves

Our Proved Undeveloped Reserves comprise approximately 13 percent of the Total Proved Reserves on a barrel of oil equivalency basis. Company Interest Proved Undeveloped Reserves of 27.7 MMboe were assigned by GLJ in accordance with NI 51-101. In general, Proved Undeveloped Reserves were assigned to certain properties because capital commitments have been made to convert the Undeveloped Reserves to Proved Producing Reserves. Proved Undeveloped Reserves have been primarily assigned for future miscible flood expansion and development drilling. Swan Hills miscible flood expansion, as well as some infill drilling, comprises roughly 17 percent of our Proved Undeveloped Reserves. The Swan Hills Unit reserves have a 50 year Remaining Reserve Life. The incremental recovery is reflected in the GLJ Report and miscible flood expansion is forecasted to continue until 2028. Similarly at Judy Creek, miscible flood development is forecast to continue until 2014 and accounts for another 17 percent of the Proved Undeveloped Reserves. In the Weyburn Unit, an additional 16 percent of the Proved Undeveloped Reserves assignment reflects the capital allocated to infill drilling and the CO_2 miscible flood. Working interest partners have committed to a CO_2 supply until 2016. Further development of the flood area in Weyburn, from the existing 57 patterns to full development with 70 patterns in the proved case, is forecast to occur by 2013. Development of all 92 patterns in the probable case continues until 2015. Given that CO_2 injection is still in the early planning and pilot stages, no full scale CO_2 flooding is being forecasted at Judy Creek.

Our ongoing CBM development requires further infill drilling and drilling extensions at Twining and Fenn Big Valley. Because of the extensive land holdings, this is forecast to occur over the next five years and represents approximately ten percent of the Proved Undeveloped Reserves. At Deer Mountain, waterflood optimization, drilling extensions and infill drilling scheduled over the next two years account for about seven percent of the Proved Undeveloped Reserves. Multi-well shallow gas infill drilling programs are scheduled for 2010 and beyond at Jenner, Patricia and Monogram, which together contain six percent of the Total Proved Undeveloped Reserves. Ongoing development is scheduled in heavy oil properties where approximately five percent of Pengrowth s Proved Undeveloped Reserves are assigned to the waterflood expansion in East Bodo that is forecast to occur over the next two years. The Olds Gas Unit contains about three percent of the total Proved Undeveloped Reserves assigned by GLJ which relate to planned recompletions for 2010.

Probable Undeveloped Reserves

Probable Undeveloped Reserves were assigned by GLJ in accordance with the requirements and standards of NI 51-101 and the COGE Handbook. Our Probable Undeveloped Reserves amount to 28.9 MMboe and represent about ten percent of the Total Proved Plus Probable Reserves. Probable Undeveloped Reserves are assigned for similar reasons and generally to the same properties as Proved Undeveloped Reserves, but also meet the requirements of the reserve classification to which they belong. Our largest Probable Undeveloped Reserves are distributed among certain properties as a percent of the total as follows: Lindbergh (22 percent), Weyburn Unit (16 percent), Swan Hills Unit (eight percent), Judy Creek Units (five percent), Carson Creek (four percent), Deer Mountain (four percent) and Goose River (four percent). At Lindbergh, Probable Undeveloped Reserves are assigned to a proposed oil sands SAGD pilot project. Facility design and procurement, delineation drilling and other development work is underway with initial production planned for 2012 and increasing over the subsequent few years.

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue calculated utilizing both constant and forecast prices and costs, undiscounted and using a discount rate of ten percent per annum for the years indicated. All of such development costs are estimated to be incurred in Canada.

Reserve Category	**2010** ($MM)	**2011** ($MM)	**2012** ($MM)	**2013** ($MM)	**2014** ($MM)	**Remainder** ($MM)	**Total Undiscounted** ($MM)	**Total Discounted at 10%** ($MM)
Proved Reserves (Constant Prices and Costs)	121	69	39	34	21	108	392	282
Proved Reserves (Forecast Prices and Costs)	155	91	58	37	24	172	537	370
Proved & Probable Reserves (Forecast Prices and Costs)	219	172	119	98	36	243	887	622

We expect to fund future development costs with a combination of cash flow, debt and equity. There are no reserves that are expected to be limited in their recovery due to their cost of development. We have established a $278 million development capital expenditure program for 2010 to fund our land acquisition, development and exploration activities, including expenditures at our proposed Lindbergh oil sands SAGD pilot project.

Finding, Development and Acquisition Costs

Finding and Development Costs

During 2009, we spent $202 million on development and optimization activities, which added 11.3 MMboe of Proved Reserves and 2.6 MMboe of Total Proved Plus Probable Reserves including revisions. The development and optimization activities exclude $5 million in expenditures mainly for information services. The largest additions were for drilling extensions at Carson Creek, infill drilling for CBM at Twining and infill drilling and improved recovery at Weyburn.

In total, we participated in drilling 169 gross wells (88.9 net wells) with a 95 percent success rate.

Extensive development occurred in the Carson Creek Beaverhill Lake Unit during 2009. A 3D seismic program was shot over this gas/condensate pool in early 2009 and nine horizontal wells were drilled in an area of the reservoir not being effectively drained by existing wells.

Table of Contents

At Judy Creek, ongoing development and optimization of the waterflood and hydrocarbon miscible flood projects continue to be a focus for us along with routine maintenance capital expenditures for facility upgrades. Similar miscible flood development as well as infill drilling occurred in the Swan Hills Unit No. 1.

Further development and optimization occurred in the Weyburn field in southeast Saskatchewan. During 2009, one horizontal producer and three horizontal injectors were drilled in the Unit. Also, four new patterns were developed in the CO_2 miscible flood project area.

In 2009, we participated in a total of 32 Horseshoe Canyon CBM wells in the Twining, Lone Pine Creek, Three Hills Creek and Fenn Big Valley areas of southern Alberta. In addition, we drilled and completed a horizontal Mannville CBM well in Fenn Big Valley during 2009.

Additional delineation of the Lindbergh oil sands pool was conducted with the drilling of five core holes, four in the vicinity of the proposed SAGD pilot project area and the fifth testing the outer limits of the pool. Ongoing engineering design work and geotechnical analysis was also conducted in preparation for initiating the pilot.

We drilled, completed and tied-in a fourth well in the Alma structure at Sable Island.

Various other drilling programs and optimization work were conducted during 2009 to increase production and maximize recoveries. In the Jenner, Bodo and Cactus Lake heavy oil areas, one horizontal and five vertical wells were drilled. Ongoing shallow gas development occurred with multi-well programs at Three Hills/Twining and Monogram (80 wells). Development drilling and facility optimization occurred in the Olds and Harmattan gas areas.

Acquisitions and Divestitures

Our acquisitions during 2009 were aimed at increasing ownership in existing core areas. We spent $35.7 million on acquisitions adding 1.3 MMboe of Proved Reserves and 1.6 MMboe of Total Proved Plus Probable Reserves. Asset acquisitions were made at Carson Creek and House Mountain, increasing existing interests in the core Judy Creek area. In addition, we increased our land ownership in the Horn River Basin shale gas play with an acquisition that closed late in the year.

During 2009, we disposed of some small, non-core properties, mainly at Niton, Karr and Pine Creek, and undeveloped acreage in Dawson. Total proceeds were $41.9 million and resulted in a decrease of 2.3 MMboe Proved Reserves and 2.9 MMboe Total Proved Plus Probable Reserves.

Future Development Capital

NI 51-101 requires that the calculation of finding and development costs include changes in forecasted future development costs (FDC) relating to the reserves. FDC reflects the amount of capital estimated by the independent evaluator that will be required to bring non-producing, undeveloped or probable reserves on stream. These forecasts of FDC will change with time due to ongoing development activity, inflationary changes in capital costs and acquisition or disposition of assets. We provide the calculation of finding, development and acquisition costs both with and without change in FDC.

2009 Finding, Development and Acquisition Costs
Company Interest Reserves
(Forecast Prices and Costs)

FD&A Costs Excluding Changes in Future Development Capital	**Proved**	**Proved plus Probable**
Exploration and Development Capital Expenditures ($M)	202,200	202,200
Exploration and Development Reserve Additions including Revisions (Mboe)(1)	11,291	2,577
Finding and Development Cost ($/boe) (1)	17.91	78.47
Net Acquisition Capital ($M)	(6,230)	(6,230)
Net Acquisition Reserve Additions (Mboe) (1)	(937)	(1,283)
Net Acquisition Cost ($/boe) (1)	6.65	4.86
Total Capital Expenditures including Net Acquisitions ($M)	195,970	195,970
Reserve Additions including Net Acquisitions (Mboe) (1)	10,354	1,294
Finding Development and Acquisition Cost ($/boe) (1)	18.93	151.41
FD&A Costs Including Changes in Future Development Capital		
Exploration and Development Capital Expenditures ($M)	202,200	202,200
Exploration and Development Change in FDC ($M)	(42,800)	(122,800)
Exploration and Development Capital including Change in FDC ($M)	159,400	79,400
Exploration and Development Reserve Additions including Revisions (Mboe) (1)	11,291	2,577
Finding and Development Cost ($/boe) (1)	14.12	30.81
Net Acquisition Capital ($M)	(6,230)	(6,230)
Net Acquisition FDC ($M)	800	800
Net Acquisition Capital including FDC ($M)	(5,430)	(5,430)
Net Acquisition Reserve Additions (Mboe) (1)	(937)	(1,283)
Net Acquisition Cost ($/boe) (1)	5.79	4.23
Total Capital Expenditures including Net Acquisitions ($M)	195,970	195,970
Total Change in FDC ($M)	(42,000)	(122,000)
Total Capital including Change in FDC ($M)	153,970	73,970
Reserve Additions including Net Acquisitions (Mboe) (1)	10,354	1,294
Finding Development and Acquisition Cost including change in FDC ($/boe) (1)	14.87	57.15

Notes:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

As reported elsewhere, reserves were removed due to changing strategy that did not meet management s objective of low-cost, repeatable resource plays. However, if these reserves would not have been removed, the Proved plus Probable FD&A without changes in FDC would have been reported as $17.80 per boe and the Proved plus Probable FD&A with changes in FDC would have been reported as $16.62 per boe.

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.

Other Oil and Gas Information

Oil and Gas Wells

As at December 31, 2009, we had an interest in 7,806 gross (3,938 net) producing oil and natural gas wells and 2,284 gross (1,230 net) non-producing oil and natural gas wells.

	Producing		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**
Crude Oil Wells				
Alberta	1,669	1,025	645	364
British Columbia	89	58	139	89
Saskatchewan	904	201	510	193
Nova Scotia				
Natural Gas Wells				
Alberta	4,954	2,543	442	239
British Columbia	142	83	98	58
Saskatchewan	29	27	41	31
Nova Scotia	19	2		

	Producing		Non-Producing	
	Gross	Net	Gross	Net
Other[(1)]				
Alberta			345	210
British Columbia			52	38
Saskatchewan			12	7
Total	**7,806**	**3,938**	**2,284**	**1,230**

Note:

(1) We cannot classify these wells as either oil or gas.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by us as at December 31, 2009 and the net area of unproved properties for which we expect our rights to explore, develop and exploit to expire during 2010.

Unproved Properties
as at December 31, 2009

Location	Gross Acres	Net Acres	Maximum Net Acres Expected to Expire During 2010
Alberta	884,573	617,850	72,204
British Columbia	299,790	174,081	9,220
Ontario	4,776		
Saskatchewan	62,297	51,708	1,318
Nova Scotia	200,650	15,957	
Total	**1,452,086**	**859,596**	**82,742**

The expiring acreage is being evaluated and attempts will be made to continue the acreage based on current activity. Historically, efforts to continue acreage on activity have been successful.

Lindbergh Oil Sands Reserves and Contingent Resources

The Lindbergh oil sands property is located approximately 420 kilometers northeast of Calgary and 65 kilometers southwest of Cold Lake. We hold a 100 percent Working Interest in this oil sands asset where oil quality averages 11°API. The Upper Lloydminster and Lower Rex are the targeted formations. These formations contain bitumen-saturated sands up to 23 meters thick at approximately 500 meters depth.

We are planning to start a pilot that is the basis for Probable Reserves and Probable plus Possible Reserves. In addition, there are Contingent Resources for the area surrounding the pilot. GLJ has updated the evaluation of the reserves and Contingent Resources for Lindbergh as of December 31, 2009. The evaluation was limited to portions of the reservoir amenable to steam assisted gravity drainage (SAGD). The project s profitability is sensitive to oil prices and is forecast to be profitable using forecast prices and costs as well as constant prices and costs.

The tables below summarize the estimated volumes of Company Interest reserves and Contingent Resources attributable to the Lindbergh property based upon forecast prices and costs. The estimates are in accordance with the definitions and guidelines in the COGE Handbook and NI 51-101. Please note that reserves and Contingent Resources involve different risks associated with achieving commerciality. Under the fiscal conditions, including commodity price and cost assumptions, applied in the estimation of reserves, the likelihood that a project will achieve commerciality is assumed to be 100 percent, whereas the likelihood of a Contingent Resource achieving commerciality may be less than 100 percent.

Probable Reserves have been assigned within the region of the proposed pilot development area. Probable plus Possible Reserves have been assigned to this same pilot area as well as a previously delineated region offsetting the pilot. There is virtually no change in the reserve estimates; however, the net present values have increased due to higher forecasted oil prices. The Probable Reserves attributed to the Lindbergh property have been included in the reserves disclosed under - *Principal Properties* and - *Statement of Oil and Gas Reserves and Reserves Data* .

Pilot Project Probable and Probable plus Possible Reserves and Net Present Value of Future Net Revenue as of December 31, 2009 (Forecast Prices and Costs)

	Probable Reserves(1)	Probable plus Possible Reserves
Reserves (MMbbl)	**6.3**	**35.8**
Before tax net present value of future net revenue		
0% discount rate ($MM)	$106.9	$1,239.0
5% discount rate ($MM)	$ 50.4	$ 339.6
10% discount rate ($MM)	$ 17.0	$ 118.7
15% discount rate ($MM)	$ (2.9)	$ 42.9
20% discount rate ($MM)	$ (14.9)	$ 9.8

Note:

(1) GLJ has estimated our undiscounted pilot capital to be $131 million and the ten percent discounted pilot capital amount to be $97 million to develop the Probable Reserves.

Contingent Resources have been assigned to the remaining areas of the reservoir within the property that meet certain minimum criteria. In order to be classified as a Contingent Resource, a technically feasible recovery project must be defined. These Contingent Resources are expected to be economic to develop. The reclassification of these Contingent Resources as reserves is contingent upon further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory application approval and company approvals. However, there is no certainty that it will be commercially viable to produce any portion of the Contingent Resource.

	December 31, 2008 Contingent Resources(1) (MMbbl)	December 31, 2009 Contingent Resources(1) (MMbbl)

Low estimate[(2)]	144.2	148.5
Best estimate[(3)]	194.2	193.4
High Estimate[(4)]	264.1	241.1

Notes:

(1) Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. The contingencies may include factors such as economics, legal, environmental, political, regulatory or lack of markets. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates.

(2) A low estimate is a conservative

estimate of the quantity of oil that will be recovered from the accumulation, which under probabilistic methodology reflects a ninety percent confidence level.

(3) A best estimate is a best estimate of the quantity of oil that will be recovered from the accumulation, which under probabilistic methodology reflects a fifty percent confidence level.

(4) A high estimate is an optimistic estimate of the quantity of oil that will be recovered from the accumulation, which under probabilistic methodology reflects a ten percent confidence level.

The accuracy of resource estimates is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. These resource volumes are classified as a resource rather than a reserve contingent upon further reservoir studies, delineation drilling and facility design, preparation of firm development plans, regulatory application approval and company approvals. The size of the resource estimate could be positively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir is larger than what is currently estimated based on the interpretation of seismic and well control. The size of the resource estimate could be negatively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir are less than what is currently estimated based on the interpretation of the seismic and well control.

Table of Contents

Forward Contracts

We may use financial derivatives or fixed price contracts to manage our exposure to fluctuations in commodity prices and foreign currency exchange rates. A description of such instruments is provided in our annual audited consolidated financial statements and related management s discussion and analysis for the year ended December 31, 2009, which may be found on SEDAR at www.sedar.com.

Additional Information Concerning Abandonment & Reclamation Costs

The total future abandonment and reclamation costs are based on management s estimate of costs to remediate, reclaim and abandon wells and facilities having regard to our Working Interest and the estimated timing of the costs to be incurred in future periods. We have developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type and size of the well or facility and the geographic location. GLJ s estimate of downhole well abandonment costs for all properties as well as abandonment costs for all Sable Island offshore and onshore facilities and pipelines upstream of the plant gate are included in their report and therefore in their estimate of future net revenue. All other abandonment and reclamation costs are not reflected in GLJ s estimate of future net revenue.

We have estimated the net present value (discounted at ten percent per annum) of our total asset retirement obligations to be approximately $214 million as at December 31, 2009, based on a total future liability (inflated at two percent per annum) of approximately $2,016 million. These costs are anticipated to be paid over 50 years with the majority of the costs incurred between 2039 and 2056 and applies to 7,299 net wells (13,344 gross wells).

The following tables summarize our total asset retirement obligations as at December 31, 2009:

Asset Retirement Obligations

	2010 ($M)	**2011** ($M)	**2012** ($M)	**Remainder** ($M)	**Total** ($M)
Total Abandonment, Reclamation, Remediation & Dismantling	12.5	7.7	9.7	1,986.3	2,016.2
Discounted at ten percent	12.0	6.7	7.7	187.2	213.6

GLJ s Proved Producing reserve evaluation includes $220 million ($78 million when discounted at ten percent) of the asset retirement obligations in the above table.

Costs Incurred

The following table outlines property acquisition, exploration and development costs that we incurred during the financial year ended December 31, 2009. These costs include only those costs which are cash or cash equivalent.

Nature of Cost	**Amount** ($M)
Acquisition Costs	
Proved	24,653
Unproved	11,002
Exploration Costs	13,915
Development Costs	188,288
Total	**237,858**

Exploration and Development Activities

The following table summarizes the number of wells completed or determined to be dry during the financial year ended December 31, 2009.

	Development		Exploration		Total	
Wells	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gas	135	67.0	1	0.5	136	67.5
Oil	13	7.3	2	2.0	15	9.3
Service	10	6.2			10	6.2
Dry	5	3.2	3	2.6	8	5.8
Total	**163**	**83.8**	**6**	**5.1**	**169**	**88.9**

See *Pengrowth Energy Trust Recent Developments 2010 Forecast Capital Production and Operating Costs* for disclosure regarding our most important current and likely exploration and development activities.

Production Estimates

The following tables summarize the 2010 average daily volume of gross production estimated by GLJ for all properties held on December 31, 2009 using constant and forecast prices and costs, all of which will be produced in Canada. These estimates assume certain activities take place, such as the development of Undeveloped Reserves, and that there are no dispositions. We estimate our 2010 production to be between 74,000 and 76,000 boepd.

	2010 Estimated Production			
	Constant Prices and Costs		Forecast Prices and Costs	
	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable
Light and Medium Crude Oil (bblpd)	20,365	21,649	20,813	21,750
Heavy Oil (bblpd)	6,947	7,260	7,039	7,350
Natural Gas (Mcfpd)	196,624	209,021	207,388	219,008
Natural Gas Liquids (bblpd)	8,654	9,983	8,832	10,053
Total (boepd)	**68,737**	**73,729**	**71,249**	**75,654**

Table of Contents

Production History (Netback)

The following tables summarize, for each quarter of our most recent financial year, certain information in respect of our production, product prices received, royalties paid, operating expenses and resulting operating netbacks:

	Quarter Ended				Year Ended
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009	December 31, 2009
Light Crude Oil					
Average Daily Oil Production[1] (bblpd)	23,424	23,078	22,930	21,948	22,841
Sales Price (after realized commodity price risk management) ($/bbl)	66.12	73.26	74.40	75.79	72.36
Processing and other income ($/bbl)	1.16	1.50	0.77	0.69	1.03
Royalties ($/bbl)	(9.28)	(12.18)	(15.94)	(17.35)	(13.65)
Amortization of injectants ($/bbl)	(2.53)	(2.56)	(2.29)	(2.19)	(2.40)
Production Costs[2] ($/bbl)	(17.98)	(18.52)	(16.54)	(17.94)	(16.28)
Operating Netback ($/bbl)	37.49	41.50	40.40	39.00	40.50
Heavy Oil					
Average Daily Oil Production[1] (bblpd)	7,672	7,822	7,480	7,235	7,551
Sales Price ($/bbl)	34.31	55.47	59.21	62.16	52.72
Processing and other income ($/bbl)	0.41	1.43	1.05	(0.84)	0.53
Royalties ($/bbl)	(4.08)	(12.05)	(6.74)	(12.81)	(8.91)
Production Costs[2] ($/bbl)	(16.59)	(11.25)	(14.18)	(12.31)	(14.35)
Operating Netback ($/bbl)	14.05	33.60	39.34	36.20	29.99
NGLs					
Average Daily NGL Production[1] (bblpd)	9,815	10,004	8,984	9,564	9,590
Sales Price ($/bbl)	35.62	36.68	41.87	54.52	42.12
Royalties ($/bbl)	(9.11)	(11.40)	(10.70)	(17.06)	(12.08)
Production Costs[2] ($/bbl)	(14.31)	(8.68)	(11.91)	(11.34)	(11.99)
Operating Netback ($/bbl)	12.20	16.60	19.26	26.12	18.05
Natural Gas					
Average Daily Gas Production[1] (Mcfpd)	236,232	247,604	232,444	232,682	237,217
Sales Price after realized commodity price risk management) ($/Mcf)	6.00	4.78	4.34	5.45	5.14
Processing and other income ($/Mcf)	0.14	0.08	0.06	0.09	0.09
Royalties ($/Mcf)	(0.45)	(0.11)	(0.12)	(0.58)	(0.31)
Production Costs[2] ($/Mcf)	(2.27)	(1.64)	(1.97)	(1.97)	(1.99)
Operating Netback ($/Mcf)	3.42	3.11	2.31	2.99	2.93

Barrels of Oil Equivalent Basis[3]

Average Daily Production[1] (boepd)	80,284	82,171	78,135	77,528	79,518
Sales Price after realized commodity price risk management) ($/boe)	44.57	44.74	45.25	50.37	46.27
Processing and other income ($/boe)	0.79	0.79	0.48	0.35	0.54
Royalties ($/boe)	(5.52)	(6.29)	(6.91)	(9.95)	(7.15)
Amortization of injectants ($/boe)	(0.74)	(0.72)	(0.67)	(0.62)	(0.69)
Production Costs[2] ($/boe)	(15.23)	(12.24)	(13.43)	(13.52)	(13.59)
Operating Netback ($/boe)	23.87	26.28	24.72	26.63	25.38

Notes:

(1) Before the deduction of royalties.

(2) Includes transportation costs. Net of processing and other income.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one boe.

Table of Contents

Before Tax Net Asset Value (NAV) at December 31, 2009

In the following table, our before tax net asset value is estimated with reference to the present value of future net cash flows before income tax from Total Proved Plus Probable Reserves, as estimated by GLJ and calculated using the forecast prices and costs shown under the heading *Pricing Assumptions* .

(amounts in $MM except for NAV per Trust Unit)	Undiscounted Amount	5% Discount Rate	10% Discount Rate	15% Discount Rate	20% Discount Rate
Undeveloped Lands[(1)]	267				
Working Capital Deficit[(2)]	(16)				
Reclamation Funds	35				
Long Term Debt	(1,128)				
Fair Value of Risk Management Contracts[(3)]	(27)				
Other Liabilities[(4)]	(84)				
Asset Retirement Obligations[(5)]	(145)				
Total Other Assets and Liabilities	(1,098)	(1,098)	(1,098)	(1,098)	(1,098)
Value of Total Proved Plus Probable Reserves[(6)]	10,143	6,630	4,885	3,865	3,202
Total Net Asset Value	9,045	5,532	3,787	2,767	2,104
NAV per Trust Unit (289.8 million Trust Units outstanding as at December 31, 2009 on an undiluted basis)	$ 31.21	$ 19.09	$ 13.06	$ 9.55	$ 7.26

Notes:

(1) Our internal estimate, calculated using the average land sale prices paid in 2009 in Alberta, Saskatchewan and British Columbia.

(2) Excludes distributions payable, current

portion of risk management contracts and future income taxes.

(3) Represents the total fair value of risk management contracts at December 31, 2009.

(4) Other liabilities include convertible debt and non-current contract liabilities.

(5) The asset retirement obligation is based on our estimate of future site restoration and abandonment liabilities, discounted at 10 percent, less that portion of the asset retirement obligations costs that are included in the value of Total Proved Plus Probable Reserves.

(6) Future net revenue prior to provisions for income tax, interest costs or general and administrative costs.

Table of Contents

TRUST UNITS

The Trust Indenture

The Trust Units, along with the class A trust units, are issued under the terms of the Trust Indenture. An unlimited number of Trust Units, class A trust units and special units may be created and issued pursuant to the Trust Indenture, of which 289,834,790 Trust Units and 888 class A trust units are issued and outstanding as at December 31, 2009. There are presently no special units outstanding. Each Trust Unit, class A trust unit and special unit represents a fractional undivided beneficial interest in the Trust.

The Trust Indenture, among other things, provides for the establishment of the Trust, the issue of Trust Units, class A trust units and special units, the permitted investments of the Trust, the procedures respecting distributions to Unitholders, the appointment and removal of Computershare as trustee, Computershare s authority and restrictions thereon, the calling of meetings of Unitholders, the conduct of business at such meetings, notice provisions, the form of trust unit certificates and the termination of the Trust. The Trust Indenture may be amended from time to time. Most amendments to the Trust Indenture, including the early termination of the Trust and the sale or transfer of the property of the Trust as an entirety or substantially as an entirety, require approval by an extraordinary resolution of the Unitholders. An extraordinary resolution of the Unitholders requires the approval of not less than 66 percent of the votes cast at a meeting of Unitholders held in accordance with the Trust Indenture at which two or more holders of at least five percent of the aggregate number of Trust Units, class A trust units and special units then outstanding are represented.

The Trust is an energy investment trust formed under the laws of the Province of Alberta which offers and sells the Trust Units to the public. The Trust Units are not deposits within the meaning of the *Canadian Deposit Insurance Corporation Act* (Canada) (CDIC Act) and are not insured under the provisions of the CDIC Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on business of a trust company.

The Trustee

Computershare, as trustee, is generally empowered by the Trust Indenture to exercise any and all rights and powers that could be exercised by the beneficial owner of the assets of the Trust. Computershare s specific responsibilities include, but are not limited to, the following: (i) reviewing and accepting subscriptions for Trust Units, class A trust units and special units and issuing Trust Units, class A trust units and special units subscribed for; (ii) subscribing for Royalty Units; (iii) issuing Trust Units in exchange for Royalty Units tendered to it for exchange; and (iv) maintaining records and providing timely reports to Unitholders. Computershare is authorized to delegate its powers and duties as trustee except as prohibited by law.

Pursuant to the Trust Indenture and the Management Agreement, Computershare, as trustee has delegated certain authority to the Corporation and the Manager to administer and regulate our day to day operations. With the expiry of the Management Agreement on June 30, 2009, it was appropriate to increase the grant of responsibility and authority to the Corporation to encompass the responsibility and authority that was formally assigned to the Manager. In addition, in keeping with the evolution of the royalty trust business model was also appropriate to generally expand the overall grant of responsibility and authority of the Corporation.

Accordingly, the Trust Indenture was amended to provide for a broader grant of responsibility and authority to the Corporation. A summary of the more significant elements of the authority and responsibility granted to the Corporation are set out below:

- preparing all returns, filings and documents for which the trustee is responsible;
- preparing and filing tax returns on behalf of the Trust and its subsidiaries;
- approving and executing continuous disclosure documents;

Table of Contents

- managing the subsidiaries of the Trust;
- overseeing the management and stewardship of the Trust s assets including the acquisition, exploration, development, operation and disposition of properties, the marketing of production and risk management provision in respect thereof;
- all matters relating to offerings of securities;
- responsibility for any take-over bid, merger, amalgamation or arrangement involving the Trust, including the implementation of any Unitholder rights protection plan;
- dealing with banks and other financial institutions;
- elections in respect of the Trust s entity classification for U.S. tax purposes;
- the maintenance of the listing of the securities of the Trust;
- the calling and holding of annual and/or special meetings of Unitholders;
- the determination and approval of distributions;
- all matters relating to the redemption of Trust Units;
- generally providing all other services and support as may be necessary or as requested by the trustee for the administration of the Trust and that are not otherwise expressly granted to the Corporation, including, but not limited to, evaluating the appropriate response to the SIFT Legislation.

Computershare, as trustee, must exercise its powers and carry out its functions under the Trust Indenture honestly, in good faith and in the best interests of the Trust and the Unitholders, and must exercise that degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Computershare is not required to devote its entire time to the business and affairs of the Trust.

Computershare, as trustee, shall be reappointed or replaced every two years as may be determined by a majority of the votes cast at an annual meeting of the Unitholders. Computershare may resign upon 60 days notice to the Corporation. Computershare may be removed by extraordinary resolution of the Unitholders or by the Corporation in certain specific circumstances. Such resignation or removal shall become effective upon the acceptance of appointment by a successor.

Stock Exchange Listings

The outstanding Trust Units are listed and posted for trading on the NYSE under the symbol PGH and on the TSX under the symbol PGF.UN . The class A trust units are not listed or posted for trading on the facilities of any stock exchange and are not transferable. Special units are not listed or posted for trading on the facilities of any stock exchange.

Ownership Restrictions

There are no restrictions on the ownership of the Trust Units or the special units. The class A trust units may only be held by individuals, corporations or other entities that are not non-residents of Canada as that term is defined in the Tax Act.

Redemption Right

The Trust Units and class A trust units are redeemable by Computershare, as trustee, on demand by a Unitholder, when properly endorsed for transfer and when accompanied by a duly completed and properly executed notice requesting redemption, at a redemption price equal to the lesser of: (i) 95 percent of the average closing price of the Trust Units on the market designated by the Board of Directors for the ten days after the Trust Units and class A trust units are surrendered for redemption and (ii) the closing price of the Trust Units on such market on the date the Trust Units and class A trust units are surrendered for redemption. The redemption right permits Unitholders to redeem Trust Units and class A trust units for maximum proceeds of $25,000 in any calendar month provided that such limitation may be waived at the discretion of the Board of Directors. Redemptions in excess of the cash limit must be satisfied by way of a distribution *in specie* of a pro rata share of Royalty Units and other assets, excluding facilities, pipelines or other assets associated with oil and natural gas production, which are held by the Trust at the time the Trust Units and class A trust units are to be redeemed. The price of Trust Units and class A trust units, as applicable, for redemption purposes is based upon the closing trading price of the Trust Units irrespective of whether the units being redeemed are Trust Units or class A trust units. The special units are redeemable by the holder thereof, when properly endorsed for transfer and when accompanied by a duly completed and properly executed notice, at a redemption price determined by the Board of Directors.

Conversion Rights

There are no conversion rights attached to the Trust Units or the special units. The class A trust units may be converted into Trust Units on a one for one basis at any time upon demand by the holder thereof.

Exchangeable Shares

The Corporation is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares have rights upon liquidation, wind-up or dissolution of the Corporation that are economically similar to the rights of Unitholders under the Trust Indenture and Royalty Indenture. No exchangeable shares are currently issued and outstanding.

Voting at Meetings of Unitholders

Meetings of Unitholders may be called on 21 days notice and may be called at any time by Computershare, as trustee, or upon written request of Unitholders holding in the aggregate not less than five percent of the aggregate number of Trust Units, class A trust units and special units then outstanding, and shall be called by Computershare and held annually. All activities necessary to organize any such meeting will be undertaken by the Corporation on behalf of Computershare. At all meetings of the Unitholders each holder is entitled to one vote in respect of each Trust Unit, class A trust unit and special unit held. Unitholders may attend and vote at all meetings of the Unitholders either in person or by proxy and a proxy holder need not be a Unitholder. Two persons present in person either holding personally or representing as proxies at least five percent of the aggregate number of Trust Units, class A trust units and special units then outstanding constitute a quorum for the transaction of business at all such meetings. Except as otherwise provided in the Trust Indenture, matters requiring the approval of the Unitholders must be approved by extraordinary resolution.

Unitholders are entitled to pass resolutions that will bind Computershare, as trustee, with respect to a limited list of matters, including but, not limited to, the following: (i) the removal or appointment of Computershare as trustee; (ii) the removal or appointment of the auditor of the Trust; (iii) the amendment of the Trust Indenture; (iv) the approval of subdivisions or consolidations of Trust Units, class A trust units and special units; (v) the sale of the assets of the Trust as an entirety or substantially as an entirety; and (vi) the termination of the Trust.

Unitholders can also consider the appointment of an inspector to investigate whether Computershare has performed its duties arising under the Trust Indenture. Such an inspector shall be appointed if a resolution approving the appointment of such inspector is passed by a majority of the votes duly cast at a meeting held for that purpose.

Table of Contents

Voting at Meetings of Corporation

Since Unitholders do not directly hold the common shares of the Corporation or the Royalty Units, they are not permitted to vote directly at meetings of the holders of the common shares and Royalty Units. However, Computershare, as trustee, is required by the Trust Indenture to vote such common shares or Royalty Units in accordance with, and subject to, the direction provided by Unitholders at meetings of the Unitholders. Computershare is not permitted to vote any common shares or Royalty Units without first receiving such direction.

Termination of the Trust

The Unitholders may vote to terminate the Trust at any meeting of such holders, subject to the following:

- a vote may be held only if: (i) requested in writing by the holders of not less than 25 percent of the Trust Units, class A trust units and special units, in the aggregate; or (ii) if the Trust Units, the class A trust units and the special units have become ineligible for investment by RRSPs, RRIFs, RESPs and DPSPs;

- the termination must be approved by extraordinary resolution of the Unitholders; and

- a quorum representing five percent of the issued and outstanding Trust Units, class A trust units and special units, in the aggregate, must be present or represented by proxy at the meeting at which the vote is taken.

If the termination is approved, Computershare, as trustee, will sell the assets of the Trust, discharge all known liabilities and obligations, and distribute the remaining assets to the Unitholders. Computershare will distribute directly to the Unitholders any assets which Computershare is unable to sell by the date set for termination.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder will be subject to any personal liability in connection with the Trust or its obligations and affairs, and the satisfaction of claims of any nature arising out of or in connection therewith is only to be made out of the Trust s assets. Additionally, the Trust Indenture states that no Unitholder is liable to indemnify or reimburse Computershare for any liabilities incurred by Computershare with respect to any taxes payable by or liabilities incurred by the Trust or Computershare, and all such liabilities will be enforceable only against, and will be satisfied only out of the Trust s assets. It is intended that the operations of the Trust will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Unitholders for claims against the Trust. Legislation has been enacted in Alberta which reduces the risk to Unitholders from the legal uncertainties regarding the potential liability of Unitholders.

Table of Contents

THE ROYALTY INDENTURE

Royalty Units

Royalty units are issued under the terms of the Royalty Indenture among the Corporation and Computershare. A maximum of 500,000,000 Royalty Units can be created and issued pursuant to the Royalty Indenture, of which 137,217,376 Royalty Units were issued and outstanding as at December 31, 2009. The Royalty Units represent fractional undivided interests in the royalty created by the Corporation in favour of holders of the Royalty Units, consisting of a 99 percent share of royalty income .

The Royalty Indenture, among other things, provides for the grant of the royalty, the issue of Royalty Units, the imposition on, and acceptance by the Corporation of, certain obligations and business restrictions, the calling of meetings of Royalty Unitholders, the conduct of business thereat, notice provisions, the appointment and removal of the trustee, and the establishment and use of the reserve as discussed below.

The Royalty Indenture may be amended or varied only by extraordinary resolution of the holders of Royalty Units, or by the Corporation and Computershare, as trustee, for certain specifically defined purposes so long as, in the opinion of Computershare, the Royalty Unitholders and the holders of Royalty Units are not prejudiced as a result.

The Royalty

The royalty consists of a 99 percent share of royalty income . Under the terms of the Royalty Indenture, the Corporation is entitled to retain a 1 percent share of royalty income and all miscellaneous income (the Residual Interest) to the extent this amount exceeds the aggregate of debt service charges, general and administrative expenses, and management fees. The Royalty Indenture provides that royalty income means the aggregate of any special distributions and gross revenue less, without duplication, the aggregate of the following amounts:

- operating costs and capital expenditures;
- general and administrative costs;
- management fees and debt service charges;
- taxes or other charges payable by the Corporation; and
- any amounts paid into the reserve .

Gross revenues generally consist of cash proceeds from the sale of petroleum substances produced from the properties of the Corporation and all other money and things of value received by or incurring to the Corporation by virtue of its legal and beneficial ownership of the properties, but not including processing, transportation, gathering, storage or treatment revenues, proceeds from the sale of properties or amounts received by the Corporation in connection with the borrowing of funds. Special distributions essentially consist of proceeds from the sale of properties that the Corporation is unable to reinvest in suitable replacement properties.

The reserve is established by the Corporation with miscellaneous revenues (such as processing and transportation revenues) and allowable portions of gross revenue, and must be used to fund the payment of operating costs, capital expenditures, future abandonments, environmental and reclamation costs, general and administrative costs, royalty income, management fees and debt service charges. The allowable portions of gross revenue consist of (i) amounts determined by the Corporation in accordance with prudent business practices for the payment of future operating costs and reclamation obligations, and (ii) amounts, not to exceed 20 percent of gross revenue, determined by the Corporation in accordance with prudent business practices to provide for the payment of future capital expenditures or for the payment of royalty income in any future period or periods. Any amounts remaining in the reserve when there are no longer any properties that are subject to the royalty, and all of the above obligations have been satisfied, are to be paid to the holders of Royalty Units in proportion to their respective interests.

The Corporation is required to pay to the holders of Royalty Units, on each cash distribution date, 99 percent of royalty income received by the Corporation from the properties for the period ending on the last day of the second month immediately preceding that cash distribution date, after the deduction of the foregoing amounts. The holders of Royalty Units, including the Trust, will reimburse the Corporation for 99 percent of the non-deductible government royalties and other non-deductible government charges payable by the Corporation in respect of production from, or ownership of, the properties. The Corporation will at all times be entitled to set off its right to be so reimbursed against its obligation to pay the royalty.

To date, the Corporation has not incurred income taxes but is subject to the Saskatchewan resource surcharge. Any taxes payable by the Corporation will reduce royalty income, and thus the distributions received by Unitholders and holders of Royalty Units.

Replacement of Properties

In the event that we determine that the sale of any of our interests in properties, and the release of the royalty would be in the best interest of the Unitholders, the Royalty Indenture permits us to make sales without the requirement of approval of the Unitholders, provided that the aggregate properties sold in any given year total less than 25 percent of our assets determined as at the date of disposition of the properties based upon an independent engineering appraisal. Any sale exceeding this threshold must be approved by an extraordinary resolution of the Unitholders.

The Trustee

Computershare is the trustee for holders of Royalty Units under the Royalty Indenture and will remain the trustee thereunder unless it resigns or is removed by Unitholders. Computershare or its successor may resign on 60 days prior notice to the Corporation, and may be removed by extraordinary resolution of the Unitholders and Royalty Unitholders collectively. Computershare s successor must be approved in the same manner.

Computershare, in accordance with its power to delegate under the Trust Indenture, has appointed the Corporation as the administrator of the Trust to assume those functions of the trustee which are largely discretionary pursuant to the Royalty Indenture.

DISTRIBUTIONS

General

We currently make monthly payments to our Unitholders on the 15th day of each month or the first business day following the 15th day. The record date for any distribution is ten business days prior to the distribution date or such other date as may be determined by the Board of Directors. In accordance with stock exchange rules, an ex-distribution date occurs two trading days prior to the record date to permit time for settlement of trades of securities and distributions must be declared a minimum of seven trading days before the record date.

Historical Distributions

A reduction in distributions from $0.17 per Trust Unit to $0.10 per Trust Unit per month was announced on February 19, 2009 commencing with the March 16, 2009 distribution. The Board of Director s stated objective in making this reduction in distributions was exercising financial prudence in uncertain times. On October 1, 2009, we announced changes to our value creation strategy to focus on investing a larger percentage of cash flow on operated, low cost, low risk, repeatable drilling opportunities in the WCSB. To provide funds for our expanded capital program, while maintaining fiscal discipline, we reduced our November 16, 2009 cash distribution by 30 percent or $0.03 per Trust Unit to $0.07 per Trust Unit. See *Pengrowth Energy Trust - Recent Developments Changes to our Value Creation Strategy* .

Distributions can and may fluctuate in the future. The availability of cash flow for the payment of distributions is derived mainly from producing and selling our oil, natural gas and related products and as such will at all times be dependent upon a number of factors, including commodity prices, production rates, proposed capital expenditures, our level of indebtedness and our ability to access equity and debt capital. The Board of Directors will continue to examine distributions on a monthly basis while considering overall market conditions prior to setting the distribution level each month. The Board of Directors cannot provide assurance that cash flow will be available for distribution to Unitholders in the amounts anticipated or at all. See *Risk Factors* .

Distributions declared in respect of 2009 production for the preceding five fiscal years were as follows:

	2009	2008	2007	2006	2005	2004
First Quarter	$ 0.30	$ 0.675	$ 0.75	$ 0.75	$ 0.69	$ 0.63
Second Quarter	0.30	0.675	0.75	0.75	0.69	0.64
Third Quarter	0.27	0.675	0.75	0.75	0.69	0.67
Fourth Quarter	0.21	0.565	0.675	0.75	0.75	0.69
Total	$ 1.08	$ 2.59	$ 2.93	$ 3.00	$ 2.82	$ 2.63

The after-tax return from an investment in Trust Units to Unitholders, for Canadian income tax purposes, can be made up of both a return on, and a return of, capital. That composition may change over time, thus affecting an investor s after-tax return. Returns on capital are generally taxed as ordinary income or as dividends in the hands of a Unitholder. Returns of capital are generally tax-deferred for Unitholders who are resident in Canada for purposes of the Tax Act (and reduce such Unitholder s adjusted cost base in the Trust Unit for purposes of the Tax Act). Returns of capital to a Unitholder who is not resident in Canada for purposes of the Tax Act or is a partnership that is not a Canadian partnership for purposes of the Tax Act will be subject to Canadian withholding tax. Prospective Unitholders should consult their own tax advisors with respect to the Canadian income tax considerations in their own circumstances. See *Certain Canadian Federal Income Tax Considerations* and *United States Federal Income Tax Considerations* in this Annual Information Form.

Since December 31, 2003, all amounts distributed to Unitholders have been treated as a return on capital (taxable income) for Canadian income and withholding tax purposes, except for amounts classified as return of capital as set out in the following table:

	2009	2008	2007	2006	2005	2004
Taxable Income(1) (per Trust Unit)	$ 1.28	$ 2.70	$ 2.78	$ 2.40	$ 2.22	$ 1.43
(percent of distributions classified as taxable income)	(100%)	(100%)	(95%)	(80%)	(80%)	(55%)
(percent of distributions classified as return of capital)	( )	( )	(5%)	(20%)	(20%)	(45%)

Note:

(1) For Canadian residents, amounts treated

as a return of capital generally are not required to be included in a Unitholder s income but such amounts will reduce the adjusted cost base to the Unitholder of the Trust Units

At the special meeting of the Royalty Unitholders held on April 23, 2002, the Royalty Unitholders approved the amendment of the Royalty Indenture to permit the Board of Directors to establish a holdback, within the Corporation, of up to 20 percent of its gross revenue if the Board of Directors determines that it would be advisable to do so in accordance with prudent business practices to provide for the payment of future capital expenditures or for the payment of royalty income in any future period. Accordingly, the Corporation would be able to apply these amounts towards capital should it be prudent to do so or keep the funds in another form to be paid out in the future, potentially stabilizing the profile of distributions paid by the Trust. Subsequent to this Royalty Unitholder action, the Board of Directors authorized the establishment of a holdback to fund future capital obligations and future payments of royalty income to the Trust comprised of funds retained within the Corporation. The Board of Directors may change the distributions or the amount withheld in the future depending on a number of factors including future commodity prices, capital expenditure requirements and the availability of debt and equity capital.

The return on an investment in Trust Units is not comparable to the return on an investment in a fixed-income security. The recovery of the initial investment made by Unitholders is at risk, and the anticipated return on the Unitholder s investment is based on many performance assumptions. Although the Trust intends to make distributions of a portion of its available cash, these cash distributions may be reduced or suspended. **Cash distributions are not guaranteed.** The ability to make cash distributions and the actual amount distributed will depend on numerous factors including, among other things: its financial performance, debt obligations, working capital requirements and future capital requirements, all of which are susceptible to a number of risks. In addition, the market value of the Trust Units may decline as a result of many factors, including its inability to meet Pengrowth s cash distribution targets in the future, and that decline may be significant. Prospective purchasers of Trust Units also should consider the particular risk factors that may affect the industry in which Pengrowth operates, and therefore the stability of the distributions they would receive. See *Risk Factors* . This section also describes Pengrowth assessment of those risk factors, as well as potential consequences to Unitholders if a risk should occur.

Restrictions on Distributions

The ability of the Trust to make cash distributions or return capital contributions to Unitholders may be directly or indirectly affected in certain events as a result of certain restrictions, including restrictions set forth in (i) the credit agreement relating to the Credit Facility, which are also incorporated by reference in the agreement relating to the $50 million demand operating line of credit; (ii) the note purchase agreements relating to the 2003 U.S. Senior Notes (as defined below), the 2007 U.S. Senior Notes, the 2008 Senior Notes and the U.K. Senior Notes (as defined below); and (iii) the Debentures. In particular, the funds required to satisfy the interest payable on the foregoing obligations, as well as the amounts payable upon the redemption or maturity of such obligations, as applicable, or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be payable as distributions to Unitholders.

Revolving Credit Facility

The credit agreement relating to the Credit Facility stipulates that the Trust shall not make or agree to make cash or other distributions or return capital contributions to Unitholders when a Default (subject to certain exceptions) or an Event of Default has occurred or is continuing or would reasonably be expected to occur as a result of such distribution or return of capital. Events of Default are defined in the credit agreement to include those events of default which are typically referred to in a loan agreement of such type and include, among other things: (i) the failure to repay amounts owing under the Credit Facility; (ii) the voluntary or involuntary insolvency of the Trust or its subsidiaries; (iii) the default of obligations owing under other debt arrangements; (iv) the change of control of the Trust; or (v) the Trust s divestiture of some or all of its debt or equity interest in the Corporation. Default is defined in the credit agreement to mean any event or circumstance which, with the giving of notice or lapse of time or otherwise, would constitute an Event of Default.

In addition to the standard representations, warranties and covenants commonly contained in a credit facility of this nature, the Credit Facility includes the following key financial covenants:

- the ratio of Consolidated Senior Debt (as defined below) to Consolidated EBITDA (as defined below) at the end of any fiscal quarter shall not exceed 3:1, except that upon the completion of a Material Acquisition (as defined below), and for a period extending to the end of the second full fiscal quarter thereafter, this limit increases to 3.5:1;

- the ratio of Consolidated Total Debt (as defined below) to Consolidated EBITDA at the end of any fiscal quarter shall not exceed 3.5:1; except that upon the completion of a Material Acquisition, and for a period extending to the end of the second full fiscal quarter thereafter, this limit increases to 4:1; and

- the ratio of Consolidated Senior Debt (as defined below) to Total Capitalization (as defined below) shall not exceed 50 percent, except that upon the completion of a Material Acquisition, and for a period extending to the end of the second full fiscal quarter thereafter, this limit increases to 55 percent.

Table of Contents

With respect to these financial covenants, the following definitions apply to the Trust and its subsidiaries on a consolidated basis:

Consolidated Senior Debt:	All obligations, liabilities and indebtedness that would be classified as debt on the consolidated balance sheet of the Trust, including, without limitation, certain items including all indebtedness for borrowed money, but excluding certain items.
Consolidated Total Debt:	The aggregate of Consolidated Senior Debt and Subordinated Debt.
Consolidated EBITDA:	The aggregate of the last four quarters net income from operations plus the sum of: income taxes; interest expense; all provisions for federal, provincial or other income and capital taxes; depreciation, depletion and amortization expense; and other non-cash amounts.
Material Acquisition:	An acquisition or series of acquisitions which increases the consolidated tangible assets of Pengrowth by more than five percent.
Subordinated Debt:	Debt which, by its terms, is subordinated to the obligations to the lenders under the Credit Facility.
Total Capitalization:	The aggregate of Consolidated Total Debt and the Unitholders equity (calculated in accordance with GAAP as shown on the Trust s consolidated balance sheet)

Senior Unsecured Notes

The terms of the note agreements relating to the 2008 Senior Notes, the 2007 U.S. Senior Notes, the U.S. $200 million of senior unsecured notes issued in 2003 to a group of U.S. investors (the 2003 U.S. Senior Notes) and the £50 million of senior unsecured ten year notes issued in 2005 to a group of U.K. based investors (the U.K. Senior Notes) ensure that note holders have priority over the Unitholders with respect to the assets and income of the Trust.

The holders of the 2003 U.S. Senior Notes, the 2007 U.S. Senior Notes, the 2008 Senior Notes and the U.K. Senior Notes are entitled to certain remedies upon the occurrence of an Event of Default , which remedies may restrict the ability of the Trust to make distributions to Unitholders. The note agreements relating to the 2003 U.S. Senior Notes, the 2007 U.S. Senior Notes, the 2008 Senior Notes and the U.K. Senior Notes contain certain restrictions on the ability of the Corporation to make payments to the Trust if, at the time thereof or if after giving effect thereto, a Default or Event of Default would exist. In addition, in connection with the note agreements relating to the 2003 U.S. Senior Notes, the 2007 U.S. Senior Notes, the 2008 Senior Notes and the U.K. Senior Notes the Trust agreed that if it has actual knowledge that Default or an Event of Default has occurred and is continuing, it will not make any payment in respect of any distribution to Unitholders. An Event of Default is defined in the note purchase agreements to include those events of default which are typically referred to in a note purchase agreement of a similar nature (including failure to pay principal and interest when due, default in compliance with other covenants, inaccuracy of representations and warranties, cross default to other indebtedness, certain events of insolvency or the rendering of judgments against the Trust in excess of certain threshold amounts). Default is defined in the note agreements to mean any event or circumstance which, with the giving of notice or lapse of time or both, would constitute an Event of Default.

In addition to standard representations, warranties and covenants, the 2003 U.S. Senior Notes, the 2007 U.S. Senior Notes, the 2008 Senior Notes and the U.K. Senior Notes also contain the following key financial covenants:

- the ratio of Consolidated EBITDA (as defined below) to interest expense for the four immediately preceding fiscal quarters shall be not less than 4:1;

- with respect to the 2003 U.S. Senior Notes and the U.K. Senior Notes only, the Consolidated Total Debt (as defined below) is limited to 60 percent of the Consolidated Total Established Reserves (as defined below) determined and calculated not later than the last day of the first fiscal quarter of the next succeeding fiscal year of the Trust;

Table of Contents

with respect to the 2007 U.S. Senior Notes and the 2008 Senior Notes, the Consolidated Total Debt (as defined below) to Total Capitalization (as defined below) shall not exceed 55 percent at the end of each fiscal quarter; and

the ratio of Consolidated Total Debt to Consolidated EBITDA for each period of four consecutive fiscal quarters shall not exceed 3.5:1.

With respect to these financial covenants, the following definitions apply to the Trust and its subsidiaries on a consolidated basis:

Consolidated EBITDA:	The sum of the last four quarters of: (i) net income determined in accordance with GAAP; (ii) all provisions for federal, provincial or other income and capital taxes; (iii) all provisions for depletion, depreciation, and amortization; (iv) interest expense; and (v) non-cash items.
Consolidated Total Debt:	Has substantially the same meaning as Consolidated Senior Debt in the definitions relating to the Credit Facility.
Consolidated Total Established Reserves:	The sum of: (i) 100 percent of the present value of Pengrowth s Proved Reserves; and (ii) 50 percent of the present value of Pengrowth s Probable Reserves.
Total Capitalization:	Consolidated Total Debt plus Unitholder equity in the Trust.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

Taxation of the Trust

SIFT Legislation

On October 31, 2006, Finance announced new proposals (the October 31 Proposals) that will change the manner in which certain flow-through entities, including mutual fund trusts, referred to as specified investment flow-through entities or SIFTs , and the distributions from such entities are taxed. The October 31 Proposals will apply a tax at the trust level on distributions of certain income from such a SIFT entity at a rate of tax comparable to the combined federal and provincial corporate tax rate and will result in the distributions from SIFT entities being treated as dividends to the recipient. The October 31 Proposals became law when Bill C-52 received Royal Assent on June 22, 2007.

With respect to structure, Pengrowth will continue to evaluate opportunities to address the imposition of the SIFT Legislation. Pengrowth currently anticipates converting to a dividend paying corporation on or before January 1, 2011. Should Pengrowth not convert to a dividend paying corporation, it is expected that the Trust will be characterized as a SIFT trust and as a result will be subject to the SIFT Legislation. The SIFT Legislation will not apply to SIFTs that were publicly traded on October 31, 2006 (Grandfathered SIFTs), such as Pengrowth, until January 1, 2011. However, the SIFT Legislation indicates that any undue expansion of a Grandfathered SIFT between October 31, 2006 and January 1, 2011 (the Interim Period), may cause the application of the SIFT Legislation to the Grandfathered SIFT to occur before January 1, 2011. Following the October 31, 2006 announcement, Finance issued a press release on December 15, 2006 wherein it provided guidelines (the Normal Growth Guidelines) as to what would be considered normal growth as opposed to undue expansion . The Normal Growth Guidelines are incorporated by reference into the SIFT Legislation.

Under the existing provisions of the Tax Act, Pengrowth can generally deduct in computing its income for a taxation year any amount of income that it distributes to Unitholders in the year and, on that basis, Pengrowth is generally not liable for any material amount of tax. The SIFT Legislation will change the manner in which the Trust and its distributions are taxed beginning January 1, 2011 (provided that the Trust is not considered to have undergone an undue expansion during the Interim Period, as set out in the Normal Growth Guidelines, which

Table of Contents

could result in the SIFT Legislation applying to the Trust at an earlier date). More specifically, the Trust will not be able to deduct certain portions of its distributed income (referred to as specified income) and will become subject to a distribution tax on such specified income at a special tax rate that approximates the tax rate applicable to a taxable Canadian corporation should it remain a SIFT after January 1, 2011.

Pengrowth anticipates that distributions received by investors subsequent to January 1, 2011 will be characterized as taxable dividends received from a taxable Canadian corporation and for a person resident in Canada, the taxable dividends will also qualify as eligible dividends.

The SIFT Legislation indicates that no change will be recommended to the 2011 date in respect of any SIFT whose equity capital grows as a result of issuances of new equity (which includes trust units, debt that is convertible into trust units, and potentially other substitutes for such equity), before 2011, by an amount that does not exceed the greater of $50 million and an objective safe harbour amount based on a percentage of the SIFT s market capitalization as of the end of trading on October 31, 2006 (measured in terms of the value of a SIFT s issued and outstanding publicly-traded units, not including debt, options or other interests that were convertible into units of the SIFT). However, under the SIFT Legislation, in the event that the Trust issues additional Trust Units or convertible debentures (or other equity substitutes) on or before 2011, the Trust may become subject to the SIFT Legislation prior to 2011. **No assurance can be provided that the SIFT Legislation will not apply to the Trust prior to 2011.** Loss of this status may result in material adverse tax consequences for the Trust and its Unitholders. However, it is assumed for the purposes of this Annual Information Form, that the Trust will not be subject to the SIFT Legislation until January 1, 2011.

The Normal Growth Guidelines provide that a SIFT s safe harbour cannot exceed its market capitalization on October 31, 2006. Pengrowth s market capitalization on October 31, 2006 was approximately $4.8 billion. Pengrowth has issued additional equity after October 31, 2006 of approximately $1.0 billion. Accordingly, Pengrowth may issue additional equity without offending the Normal Growth Guidelines of approximately $3.8 billion. Pengrowth has adhered to the normal growth limits from October 31, 2006 to the date hereof.

The SIFT Legislation will result in material and adverse tax consequences to the Trust and its Unitholders (most particularly investors that are tax exempt or non-residents of Canada as such Unitholders are not entitled to the benefit of the eligible dividend tax treatment that is available to taxable Canadian individuals). It is expected that the imposition of tax at the trust level under the October 31 Proposals will materially reduce the amount of cash available for distributions to Unitholders should Pengrowth not convert to a dividend paying corporation on or before January 1, 2011.

Taxation of Unitholders Resident in Canada

Under the existing provisions of the Tax Act, a Unitholder that is a resident of Canada for purposes of the Tax Act is generally required to include in computing income for a particular taxation year that portion of the net income of the Trust that is paid or payable to the Unitholder in that taxation year and such income to the Unitholder will generally be considered to be ordinary income from property.

Pursuant to the SIFT Legislation, amounts in respect of the Trust s income payable to Unitholders that is not deductible by the Trust will be treated as a taxable dividend from a taxable Canadian corporation. Dividends received or deemed to be received by an individual (other than certain trusts) will be included in computing the individual s income for tax purposes and will be subject to the enhanced gross-up and dividend tax credit rules under the Tax Act normally applicable to eligible dividends received from taxable Canadian corporations. Dividends received or deemed to be received by a holder that is a corporation will generally be deductible in computing the corporation s taxable income. Certain corporations, including private corporations or subject corporations (as such terms are defined in the Tax Act), may be liable to pay a refundable tax under Part IV of the Tax Act of 33 1/3 percent on dividends received or deemed to be received to the extent that such dividends are deductible in computing taxable income. Unitholders that are trusts governed by registered retirement savings plans, registered retirement income funds, registered education savings plans, deferred profit sharing plans and tax-free savings accounts as defined in the Tax Act (referred to herein as Exempt Plans) will generally continue not to be liable for tax in respect of any distributions received from the Trust. Although the SIFT Legislation will not increase the tax payable by Exempt Plans in respect of dividends deemed to be received from the Trust, it is expected that the imposition of tax at the Trust level under the SIFT Legislation will materially reduce the amount of cash available for distributions to Unitholders.

Returns of capital are, and will be under the SIFT Legislation, generally tax deferred for Unitholders who are resident in Canada for purposes of the Tax Act and will reduce such Unitholder s adjusted cost base in the Trust Units for purposes of the Tax Act.

Taxation of Unitholders who are Non-Residents of Canada

Under the existing provisions of the Tax Act, any distribution of income by the Trust to a non-resident of Canada (Non-Resident Unitholder) will be subject to Canadian withholding tax at the rate of 25 percent unless such rate is reduced under the provisions of a convention between Canada and the Non-Resident Unitholder s jurisdiction of residence. A Non-Resident Unitholder resident in the United States who is entitled to claim the benefit of the Canada-U.S. Convention, will generally be entitled to have the rate of withholding reduced to 15 percent of the amount of any income distributed. Under the Canada-U.S. Convention, certain tax-exempt organizations resident in the U.S. may be entitled to an exemption from Canadian withholding tax.

Pursuant to the SIFT Legislation, amounts in respect of the Trust s income payable to Non-Resident Unitholders that are not deductible to the Trust will be treated as a taxable dividend from a taxable Canadian corporation. Such dividends will be subject to Canadian withholding tax at a rate of 25 percent, unless such rate is reduced under the provisions of a convention between Canada and the Non-Resident Unitholder s jurisdiction of residence. A Non-Resident Unitholder resident in the United States who is entitled to claim the benefit of the Canada-US Convention generally will be entitled to have the rate of withholding reduced to 15 percent of the amount of such dividend. Although the SIFT Legislation may not increase the tax payable by Non-Resident Unitholders in respect of dividends deemed to be paid by the Trust, it is expected that the imposition of tax at the Trust level under the SIFT Legislation would materially reduce the amount of cash available for distributions to Unitholders should Pengrowth not convert to a dividend paying corporation.

Returns of capital to a Unitholder who is not a resident of Canada for purposes of the Tax Act or is a partnership that is not a Canadian partnership for purposes of the Tax Act are, and will be under the SIFT Legislation, subject to a 15 percent Canadian withholding tax.

On September 21, 2007, Canada and the United States signed the Protocol to the Canada-U.S. Convention. The Protocol came into force on December 15, 2008, when the two countries formally notified each other that their procedures were complete. The Protocol contains new Article IV(7)(b), a treaty benefit denial rule, which would have increased the Canadian withholding tax on Pengrowth s distributions to Non-Resident Unitholders who are residents of the US for the purposes of the Canada-US Convention from 15 percent to 25 percent commencing on January 1, 2010 had Pengrowth not elected to be a corporation for United States federal income tax purpose on July 1, 2009. The effect of Pengrowth s election to be treated as a corporation is to maintain the current withholding tax rate of 15 percent and not subject its U.S. investors to an increase in the 15 percent withholding tax on their distributions starting January 1, 2010. Returns of capital would still be subject to a 15 percent Canadian withholding tax and such rate is not modified by the Protocol. The Protocol also contains measures which, generally speaking, are designed to limit the benefits under the Canada-U.S. Convention to treaty shopping transactions or arrangements.

Subject to certain limitations set forth in the United States Internal Revenue Code of 1986, as amended, United States holders may elect to claim a foreign tax credit against their United States federal income tax liability for net Canadian income tax withheld from distributions received in respect of Trust Units that is not refundable to the United States holder and for any Canadian income taxes paid by us. The SIFT Legislation will apply a tax at the trust level on distributions of certain income from a SIFT trust. It is unclear whether this tax will constitute an income tax or a tax imposed in lieu thereof for purposes of the foreign tax credit rules; if it does not constitute such a tax it will not be creditable. The limitation on foreign taxes eligible for credit is calculated separately with respect to specific classes of income. Distributions with respect to Trust Units will be passive category income or general category income for purposes of computing the foreign tax credit allowable to a United States holder. If the tax at the trust level on distributions of certain income from a SIFT trust constitutes a creditable tax, such distributions likely would be general category income for purposes of computing the foreign tax credit allowable to a United States holder. The rules and limitations relating to the determination of the foreign tax credit are complex and prospective purchasers are urged to consult their own tax advisors to determine whether or to what extent they would be entitled to such credit. United States persons that do not elect to claim foreign tax credits may instead claim a deduction for their share of Canadian income taxes paid by us or withheld from distributions by us. **This Annual Information Form may not describe the United States tax consequences of the purchase, holding or disposition of the Trust Units fully. Non-Resident Unitholders should obtain independent tax advice as necessary.**

The SIFT Legislation may have a material and adverse impact on the Trust and its Unitholders. Unitholders are urged to consult their own tax advisors having regard to their own particular circumstances should Unitholders not approve Pengrowth s conversion to a dividend paying corporation. See *Risk Factors The SIFT Legislation has and may continue to materially and adversely affect the Trust, the Unitholders and the value of the Trust Units*.

UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following discussion is a summary of certain United States federal income tax consequences of the ownership and disposition of Trust Units to United States Holders (as defined below). This discussion is based on the United States Internal Revenue Code of 1986, as amended (the Code), administrative pronouncements, judicial decisions, existing and proposed Treasury regulations, the Canada-U.S. Convention and interpretations of the foregoing, all as of the date hereof. All of the foregoing authorities are subject to change (possibly with retroactive effect), and any such change may result in United States federal income tax consequences to a United States Holder that are materially different from those described below. No rulings from the United States Internal Revenue Service (the IRS) have been or will be sought with respect to the matters described below, and consequently, the IRS may disagree with the description below, and it may not be upheld upon review in court.

The following discussion does not purport to be a full description of all United States federal income tax considerations that may be relevant to a United States Holder in light of such holder s particular circumstances and only addresses holders who hold Trust Units as capital assets within the meaning of Section 1221 of the Code. Furthermore, this discussion does not address the United States federal income tax considerations applicable to holders subject to special rules, such as (i) persons that are not United States Holders; (ii) certain financial institutions, real estate investment trusts, regulated investment companies or insurance companies; (iii) tax-exempt organizations, qualified retirement plans, individual retirement accounts, or other tax-deferred accounts; (iv) traders in securities that elect to use a mark-to-market method of accounting; (v) dealers in securities or currencies; (vi) persons holding Trust Units in connection with a hedging transaction, straddle , conversion transaction or other integrated transaction; (vii) persons that acquired the Trust Units in connection with the exercise of employee stock options or otherwise as compensation for services; (viii) persons that own directly, indirectly or constructively ten percent or more, by voting power, of the outstanding equity interests of the Trust; (ix) persons whose functional currency is not the United States dollar; (x) persons subject to the alternative minimum tax; and (xi) United States expatriates. In addition, this discussion does not include any description of any estate and gift tax consequences, or the tax laws of any state, local or other government that may be applicable.

As used herein, the term United States Holder means a beneficial owner of a Trust Unit that is (i) a citizen or individual resident of the United States as such residency is determined for United States federal income tax purposes, (ii) a corporation or other entity taxable as a corporation organized in or under the laws of the United States or any political subdivision thereof, (iii) an estate the income of which is subject to United States federal income taxation without regard to the source thereof or (iv) a trust if a United States court has primary supervision over its administration and one or more United States persons have the authority to control all substantial decisions of the trust, or if the trust has a valid election in effect under applicable Treasury Regulations to be treated as a United States person.

Table of Contents

If a pass-through entity, including a partnership or other entity classified as a partnership for United States federal income tax purposes, is a beneficial owner of Trust Units, the United States federal income tax treatment of an owner or partner generally will depend upon the status of such owner or partner and upon the activities of the pass-through entity. Any owner or partner of a pass-through entity holding Trust Units is urged to consult its own tax advisor.

Classification of the Trust as a Corporation

The Trust has elected under applicable Treasury Regulations to be treated as a corporation for United States federal income tax purposes effective July 1, 2009. Consequently, United States Holders will be subject to United States federal income tax on distributions received from the Trust and dispositions of Trust Units as described below.

Ownership and Disposition of Trust Units

Distributions

Subject to the discussion below under *PFIC Status*, the gross amount of any distribution of cash or property (other than in liquidation) made to a United States Holder with respect to Trust Units (inclusive of any Canadian withholding tax with respect thereto) generally will be includible in income by a United States Holder as dividend income to the extent such distribution is paid out of the current or accumulated earnings and profits of the Trust as determined under United States federal income tax principles. Dividends will not be eligible for the dividends received deduction generally allowed to a United States corporation on dividends received from a domestic corporation. A distribution in excess of the Trust s current and accumulated earnings and profits will first be treated as a tax-free return of capital to the extent of a United States Holder s adjusted tax basis in its Trust Units and will be applied against and reduce such basis on a dollar-for-dollar basis (thereby increasing the amount of gain and decreasing the amount of loss recognized on a subsequent disposition of Trust Units). To the extent that such distribution exceeds the United States Holder s adjusted tax basis, the distribution will be treated as capital gain, which will be treated as long-term capital gain if such United States Holder s holding period in its Trust Units exceeds one year as of the date of the distribution and otherwise will be short-term capital gain.

Under current law, the amount of distributions treated as taxable dividends received by non-corporate United States Holders will be qualified dividend income to such United States Holders, provided certain holding period and other requirements (including a requirement that the Trust is not a passive foreign investment company (a PFIC) in the year of the dividend or the preceding year) are satisfied and the Trust is eligible for benefits under the Canada-U.S. Convention or Trust Units are readily tradable on an established United States securities market. Qualified dividend income received from the Trust before January 1, 2011 will be subject to a maximum rate of United States federal income tax of 15 percent to a United States Holder that is not a corporation, including an individual.

Sale, Exchange or Other Taxable Disposition of Trust Units

Subject to the discussion below under *PFIC Status*, for United States federal income tax purposes, a United States Holder will generally recognize gain or loss on the sale, exchange, or other taxable disposition of any of its Trust Units in an amount equal to the difference between (i) the United States dollar value of the amount realized for the Trust Units and (ii) the United States Holder s adjusted tax basis (determined in United States dollars) in the Trust Units. Such gain or loss recognized by a United States Holder will be a capital gain or loss. Capital gains of non-corporate United States Holders derived with respect to a sale, exchange, or other disposition of Trust Units held for more than one year are generally subject to preferred rates. The deductibility of capital losses is subject to limitations. Any gain or loss recognized by a United States Holder will generally be treated as United States source gain or loss for foreign tax credit limitation purposes.

Table of Contents

PFIC Status

A non-United States entity treated as a corporation for United States federal income tax purposes will be a PFIC for any taxable year in which, after taking into account the income and assets of the corporation and certain subsidiaries, either (1) at least 75 percent of its gross income is passive income or (2) at least 50 percent of the average value of its assets is attributable to assets that produce passive income or are held for the production of passive income.

Based on its current operations, the Trust believes that it is currently not a PFIC and is not expected to be a PFIC for 2010 or for any subsequent taxable year. However, PFIC status is fundamentally factual in nature, generally cannot be determined until the close of the taxable year in question and is determined annually. Consequently, there is no assurance that the Trust will not become a PFIC for any taxable year during which a United States Holder holds Trust Units.

If the Trust were classified as a PFIC, for any year during which a United States Holder owns Trust Units (regardless of whether the Trust continues to be a PFIC), the United States Holder would be subject to special adverse rules, including taxation at maximum ordinary income rates plus an interest charge on both gains on sale and certain dividends, unless the United States Holder makes an election to be taxed under an alternative regime. In addition, any dividends paid by a PFIC would not be qualifying dividends, and would not be eligible for the reduced rate that currently applies to certain dividends received by United States Holders that are not corporations.

Certain elections may be available to a United States Holder if the Trust were classified as a PFIC. The Trust will provide United States Holders with information concerning the potential availability of such elections if the Trust determines that it is or will become a PFIC.

Other Considerations

Foreign Tax Credits

Any tax withheld by Canadian taxing authorities with respect to distributions on, or proceeds from disposition of, Trust Units may, subject to a number of complex limitations, be claimed as a foreign tax credit against a United States Holder s United States federal income tax liability or may be claimed as a deduction for United States federal income tax purposes. The limitation on foreign taxes eligible for credit is calculated separately with respect to specific classes of income. For this purpose, dividends distributed with respect to Trust Units will be foreign-source income and will be passive category income or general category income for purposes of computing the foreign tax credit allowable to a United States Holder, and gain recognized on the sale of Trust Units will generally be treated as United States source for such purposes. Because of the complexity of the limitations on the use of foreign tax credits, each United States Holder should consult its own tax advisor with respect to the amount of foreign taxes that may be claimed as a credit.

The Receipt of Canadian Currency

Taxable dividends with respect to Trust Units that are paid in Canadian dollars will be included in the gross income of a United States Holder as translated into United States dollars calculated by reference to the exchange rate prevailing on the date of actual or constructive receipt of the Canadian dollars, regardless of whether the Canadian dollars are converted into United States dollars at that time. The amount realized upon the sale, exchange or other taxable disposition of Trust Units will generally be based on the United States dollar value of the Canadian dollars received on the settlement date of the disposition. If the Canadian dollars received are not converted into United States dollars on the date of receipt, a United States Holder will have a basis in the Canadian dollars equal to its United States dollar value on the date of receipt. Any United States Holder who receives payment in Canadian dollars and engages in a subsequent conversion or other disposition of the Canadian dollars may have a foreign currency exchange gain or loss that will be treated as ordinary income or loss, and generally will be United States source income or loss for foreign tax credit purposes.

United States Holders are urged to consult their own tax advisors concerning the United States tax consequences of acquiring, holding and disposing of Canadian dollars.

Information Reporting and Backup Withholding

A United States Holder may be subject to United States information reporting and backup withholding tax on distributions paid on Trust Units or proceeds from the disposition of Trust Units. Information reporting and backup withholding will not apply, however, to a United States Holder that is a corporation or is otherwise exempt from information reporting and backup withholding and, when required, demonstrates this fact. Backup withholding also will not apply to a United States Holder that furnishes a correct taxpayer identification number and certifies on a Form W-9 or successor form, under penalty of perjury, that it is not subject to backup withholding, and otherwise complies with applicable requirements of the backup withholding rules. A United States Holder that fails to provide the correct taxpayer identification number on Form W-9 or successor form may be subject to penalties imposed by the IRS. Backup withholding, currently at a 28-percent rate, is not an additional tax, and any amount withheld under these rules will be allowed as a refund or credit against a United States Holder s United States federal income tax liability if the required information is timely furnished to the IRS.

UNITED STATES HOLDERS SHOULD CONSULT THEIR TAX ADVISORS REGARDING THE TAX CONSEQUENCES TO THEM OF THE OWNERSHIP AND DISPOSITION OF THE TRUST UNITS, INCLUDING THE EFFECTS OF UNITED STATES FEDERAL, STATE AND LOCAL, NON-UNITED STATES AND OTHER TAX LAWS.

INDUSTRY CONDITIONS

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulation imposed by various levels of government. Although we do not expect that these controls and regulation will affect the operations of Pengrowth in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and Pengrowth is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms and the world price of oil. Oil exports may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board. 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 National Energy Board and the issuance of such licence requires approval of the Governor in Council.

Pricing and Marketing Natural Gas

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the National Energy Board 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 criteria prescribed by the National Energy Board and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to twenty years (in quantities of not more than 30,000 m3/day), must be made pursuant to an order of the National Energy Board. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the National Energy Board and the issue of such a license requires the approval of the Governor in Council.

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

Pricing and Marketing Natural Gas Liquids

In Canada, the price of NGLs sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical feed stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are subject to regulation by the National Energy Board 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 criteria prescribed by the National Energy Board and the Government of Canada. NGLs may be exported for a term of no more than one year in respect to propane and butane, and no more than two years in respect to ethane, all exports requiring an order of the National Energy Board.

Royalties

For crude oil, natural gas and related production from federal or provincial government lands, the royalty regime is a significant factor in the profitability of production operations. Royalties payable on production from lands other than government Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on well productivity, geographic location and field discovery date.

From time to time, the provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Royalties payable pursuant to petroleum and natural gas leases with the Government of Alberta are *ad valorem* royalties calculated using the oil or natural gas price and the amount of monthly production.

The Government of Alberta changed the royalty rates effective January 1, 2009 and subsequently added a new well royalty reduction incentive program effective April 1, 2009. The Province has two different royalty programs: the New Royalty Framework and Transitional Royalties.

The New Royalty Framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new royalty framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from zero to 50 percent. Natural gas royalty rates range from five to 50 percent. Propane and butanes will have fixed royalty rates of 30 percent, whereas pentanes plus will have a fixed royalty rate of 40 percent. The sulfur royalty rate remains unchanged at 16 percent.

The new well royalty reduction incentive program provides $200 per metre drilled royalty credit as well as a five percent royalty rate for the first year of production subject to 50,000 barrel of oil or 500 million cubic feet of gas limitation. The drill credit is limited based on a sliding scale of 2008 Crown production; Pengrowth s drill credit limit is twenty percent of Alberta Crown royalties.

In November 2008, the Alberta Government announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 and 3,500 metres, which are spud between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new Transitional Royalty rates or the New Royalty Framework rates. Under certain conditions, the transition option provides lower royalties in the initial years of a well s life. For example, under the transition option, royalty rates for natural gas wells will range from five to 30 percent. The election must be made prior to the end of the first calendar month in which the leased substance is produced. All wells using the Transitional Royalty rates shift to the New Royalty Framework rates on January 1, 2014.

The Deep Oil Exploration Program (DOEP) and the Natural Gas Deep Drilling Program (NGDDP) are new programs that began January 1, 2009. These programs provide royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 meters with a Crown interest and must be spud after January 1, 2009. These oil wells qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production, whichever comes first. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 meters. The NGDDP will have an escalating royalty credit in line with progressively deeper wells from $625 per meter to a maximum of $3,750 per meter. There are additional benefits for the deepest wells. Both the DOEP and the NGDDP are five year programs. Any wells spud after December 31, 2013, or any wells that choose the transition option, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018.

Approximately 68 percent of our Company Interest production forecast for 2010 is in the Province of Alberta on Crown lands.

British Columbia

In May 2008, the Government of British Columbia introduced the Net Profit Royalty Program, which is governed by the *Net Profit Royalty Regulation,* in order to stimulate development of high risk and high cost natural gas and oil resources in British Columbia that are not economic under other royalty programs. Under the program, producers can apply to have royalties for a particular project based on the net profits of the project, rather than on simple production figures.

The Province of British Columbia announced an Oil and Gas Stimulus Package on August 6, 2009. This stimulus package included a one year, two percent royalty rate for all wells drilled from September 2009 through June 2010, an increase in deductions for natural gas deep drilling and the inclusion of 1,900 to 2,300 metre horizontal wells in the Deep Royalty Program. The British Columbia natural gas royalty regime is price sensitive, using a select price as a parameter in the royalty rate formula. When the reference price, being the greater of the producer price or the Crown set posted minimum price (PMP), is below the select price, the royalty rate is fixed. The rate increases as prices increase above the select price. The Government of British Columbia determines the producer prices by averaging the actual selling prices for gas sales with shared characteristics for each company minus applicable costs. If this price is below the PMP, the PMP will be the price of the gas for royalty purposes.

Natural gas is classified as either conservation gas or non-conservation gas . There are three royalty categories applicable to non-conservation gas, which are dependent on the date on which title was acquired from the Crown and on the date on which the well was drilled. The base royalty rate for non-conservation gas ranges from nine to 15 percent. A lower base royalty rate of eight percent is applied to conservation gas. However, the royalty rate may be reduced for low productivity wells.

The royalty regime for oil is dependent on age and production. Oil is classified as old , new or third tier and a separate formula is used to determine the royalty rate depending on the classification. The rates are further varied depending on production. Lower royalty rates apply to low productivity wells and third tier oil to reflect the increased cost of exploration and extraction. There is no minimum royalty rate for oil.

Table of Contents

Approximately five percent of our Company Interest production forecast for 2010 is in the Province of British Columbia on Crown lands.

Saskatchewan

Crown royalty rates are sensitive to the individual productivity of each well. The rates are applied to the respective portions of each classification of gas (fourth tier gas , third tier gas , new gas and old gas) produced from a well. Each month, the royalty rates are adjusted based on the level of the Provincial Average Gas Price (PGP) established by the Province monthly. The PGP represents the weighted average fieldgate price (expressed in $\$/10^3m^3$) received by producers during the month for the sale of all gas subject to royalty. Crown royalty of the production volume is calculated on each individual well using the applicable royalty rate to the volume of gas produced by each well on a monthly basis.

The operator must elect to use either the PGP or the Operator Average Gas Price (OGP) for purposes of valuing the Crown s royalty share of the production volume from each well. The OGP is determined each month by the operator and represents the weighted average fieldgate price ($\$/10^3m^3$) received by the operator for sales of gas during the month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month.

Crown royalty rates are sensitive to the individual productivity of each well and the type of oil produced from the well. Each month, royalty rates are adjusted based on the level of the reference price established by the Province for each type of oil.

For Crown royalty purposes, crude oil is classified as heavy oil , southwest designated oil or non-heavy oil other than southwest designated oil . There are separate reference prices established for each type of oil which represent the average wellhead price (in $\$/m^3$) received by producers during the month for sales of that oil type in Saskatchewan. The Crown royalty share of production volume is calculated on each individual well using the applicable royalty rate to the volume of oil produced from the well each month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the oil for the month.

A separate cost sensitive royalty structure applies to incremental production from enhanced oil recovery projects, which incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.

Approximately seven percent of our Company Interest production forecast for 2010 is in the Province of Saskatchewan.

Nova Scotia

The Government of Nova Scotia has established a generic royalty regime in respect of oil and gas produced from offshore Nova Scotia based on revenues and profits. Such regime contemplates a multi-tier royalty in which the royalty rate fluctuates when certain threshold levels of rates of return on capital have been reached and offers lower royalties for a first project in a new area, being a high risk project . Notwithstanding the generic royalty regime, royalties in respect of offshore Nova Scotia oil and gas production may be determined contractually between the participant and the Government of Nova Scotia.

Approximately seven percent of our Company Interest production forecast for 2010 is in the Province of Nova Scotia.

Table of Contents

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licenses and authorizations or civil liability for pollution damage.

Climate Change

Federal

The Canadian federal government has indicated an intention to regulate emissions of industrial GHG emissions from a broad range of industrial sectors in the *Regulatory Framework for Air Emissions* released April 26, 2007 (the Framework) and updated in a March 10, 2008 document entitled *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (collectively, the Federal Plan). The Federal Plan outlines proposed policies to reduce GHG emissions intensity of regulated facilities. New facilities will face reduction requirements, beginning in their fourth year of commercial production, of 2 percent per year from their baseline emissions intensity (e.g. the emissions intensity of their third year of commercial production) until at least 2020. Targets will be based on a cleaner fuel standard (i.e. the use of natural gas as a fuel) for new facilities commencing production before 2012, although new facilities commencing production in 2012 or later that are built carbon-capture ready will not need to meet the cleaner fuel standard until 2018. Compliance options under the Federal Plan will include: making emissions intensity improvements, making investments in certified carbon capture and storage projects (until 2018), buying offsets or emissions performance credits, and, for a portion of each entity s emissions reduction obligations (the portion would start at 70 percent and decline to zero percent in 2018), making payments to the federal technology fund.

The Canadian federal government currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs and industrial air pollutants, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. Announcements from the Canadian federal government indicate an interest in creating a North American cap and trade system with hard caps on emissions from facilities rather than emissions intensity limits. No assurance can be given that either a modified Federal Plan or a North American cap and trade system will or will not be implemented, or what obligations might be imposed under any such system.

The Framework also outlines proposed requirements by the Canadian federal government governing the emission of industrial air pollutants. Proposed compliance mechanisms include fixed emission caps and an emissions credit trading system for certain industrial air pollutants, as well as several options from which companies may choose to meet GHG emission reduction targets. The current status of these proposals is unclear. The Canadian federal government currently imposes reporting obligations under the *Canadian Environmental Protection Act, 1999* for facilities that create GHG emissions over 50,000 tonnes CO_2e in any year.

As the details of the implementation of any federal legislation for GHGs or industrial pollutants have not been announced, the effect on Pengrowth s operations cannot be determined at this time.

Alberta

Alberta regulates GHG emissions under the *Climate Change and Emissions Management Act*, the *Specified Gas Reporting Regulation* (the SGRR), which imposes GHG emissions reporting requirements, and the *Specified Gas Emitters Regulation* (the SGER) which imposes GHG emissions limits.

Table of Contents

Effective 2010, under the SGRR, Pengrowth must report if it has GHG emissions of 50,000 tonnes CO_2e or more from a facility in any year. Currently, we have three facilities that meet this threshold. Under the SGER, GHG emission limits apply once a facility has direct GHG emissions in a year of 100,000 tonnes CO_2e or more. We currently have two facilities that meet this threshold. Under the SGER, any facility coming into commercial production after 2000 will be considered a new facility and will be required to reduce its emission intensity (e.g. tonnes of GHGs emitted per unit of production) by 2 percent per year beginning in its fourth year of commercial operation, up to an aggregate 12 percent reduction from the emissions intensity level of its third year of commercial operation.

The SGER permits Pengrowth to meet the applicable emission limits by making emissions intensity improvements at facilities, offsetting GHG emissions by purchasing offset credits or emission performance credits in the open market, or acquiring fund credits by making payments of $15/per tonne to the Alberta Climate Change and Management Fund. The Alberta government intends to raise the price of fund credits and increase the required reductions in GHG emissions intensity to unspecified levels. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations. Under the Alberta regulations, if the emissions remain at current levels, Pengrowth would be required to purchase off-setting credits in 2010 of up to $300,000 from Alberta Environment. In 2009, Pengrowth spent $165,885 on purchasing off-setting credits for the Olds Gas Plant. The Judy Creek Gas Conservation Plant did not need to purchase off-setting credits as it had a surplus of carbon credits.

British Columbia

The Province of British Columbia intends to reduce its GHG emissions to 33 percent below 2007 levels by 2020 and has set interim targets of 6 percent below 2007 levels by 2012 and 18 percent below 2007 levels by 2016 and, accordingly, has implemented the *Greenhouse Gas Reduction Targets Act*. The Crown is obliged to report every second year on the amount of reductions achieved in the province, although there is no mechanism in place to measure compliance nor is there any consequence for failing to reach the target. A carbon tax was implemented on the purchase or use of fossil fuels within the Province of British Columbia, starting at $10/ton on July 1, 2008 and rising by $5 per year to $30/ton in 2012. This carbon tax is mostly collected at the wholesale level, but is collected at the retail level for marketable natural gas and propane. Carbon capture and storage is required for all coal-fired electricity generation facilities and a 0.4 percent levy tax has been implemented at the consumer level on electricity, natural gas, grid propane and heating oil that goes towards establishing a Clean Energy Fund.

Saskatchewan

On May 11, 2009, the Province of Saskatchewan introduced Bill 95 *An Act Respecting the Management and Reduction of Greenhouse Gases and Adaptation to Climate Change.* The new legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulation.

Nova Scotia

The Province of Nova Scotia has set a goal of lowering GHG emissions by 10 percent below 1990 levels by 2020 and has implemented the *Environmental Goals and Sustainable Prosperity Act*. The Crown must report annually the amount of reductions achieved in the Province but there is no mechanism for measuring compliance nor are there any consequences for failing to meet the goal.

General Discussion

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect Pengrowth s business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce Pengrowth s emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects.

Table of Contents

Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations requirements may materially adversely affect Pengrowth s business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by Pengrowth or by consumers of Pengrowth s products. The imposition of such measures might negatively affect Pengrowth s costs and prices for Pengrowth s products and have an adverse effect on earnings and results of operations.

RISK FACTORS

If any of the following risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in distributions on, and the market price of, our Trust Units. As a result, the trading price of our Trust Units could decline, and you could lose all or part of your investment. ***Additional risks are described under the heading Business Risks in our Management s Discussion and Analysis for the year ended December 31, 2009.***

Low 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 amount of distributions to our Unitholders.

The monthly distributions we pay to our Unitholders depend, in part, on the prices we receive for our oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond our control. While oil prices are set in a much broader global market, natural gas prices are largely dependant on North American economies. Additional factors include:

- global energy policy, including the ability of OPEC to set and maintain production levels for oil;
- geo-political conditions;

worldwide economic conditions;

weather conditions including weather-related disruptions to the North American natural gas supply;

the supply and price of foreign oil and natural gas;

the level of consumer demand;

the price and availability of alternative fuels;

the proximity to, and capacity of, transportation facilities;

the effect of worldwide energy conservation measures; and

government regulation.

Declines in oil or natural gas prices could have an adverse effect on our operations, financial condition and Proved Reserves and ultimately on our ability to pay distributions to our Unitholders.

Distributions may be reduced during periods of lower operating cash flow, which result from lower commodity prices and the decision by Pengrowth to make capital expenditures using cash flow. A reduction in distributions could also negatively affect the market price of the Trust Units.

Production and development costs incurred with respect to properties, including power costs and the costs of injection fluids associated with tertiary recovery operations, reduce the royalty income that the Trust receives and, consequently, the amounts we can distribute to our Unitholders.

The timing and amount of capital expenditures will directly affect the amount of income available for distribution to our Unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made. To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand oil and gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use cash flow to finance capital expenditures or property acquisitions, the cash the Trust receives from the Corporation on the Royalty Units will be reduced, resulting in reductions to the amount of cash we are able to distribute to our Unitholders. A reduction in the amount of cash distributed to Unitholders may negatively affect the market price of the Trust Units.

Actual reserves will vary from reserve estimates, and those variations could be material and may negatively affect the market price of the Trust Units and distributions to our Unitholders.

The value of the Trust Units will depend upon, among other things, our reserves. In making strategic decisions, we generally rely upon reports prepared by our independent reserve engineers. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, our Trust Units. The reserve and cash flow information contained herein represent estimates only. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

historical production from the area compared with production rates from similar producing areas;

the assumed effect of government regulation;

assumptions about future commodity prices, exchange rates, production and development costs, capital expenditures, abandonment costs, environmental liabilities, and applicable royalty regimes;

initial production rates;

production decline rates;

ultimate recovery of reserves;

marketability of production; and

other government levies that may be imposed over the producing life of reserves.

If any of these factors and assumptions proves to be inaccurate, our actual results may vary materially from our reserve estimates. Many of these factors are subject to change and are beyond our control. In particular, changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, our Trust Units. In addition, all such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. A significant portion of our reserves are classified as undeveloped and are subject to greater uncertainty than reserves classified as developed .

In accordance with normal industry practices, we engage independent petroleum engineers to conduct a detailed engineering evaluation of our oil and gas properties for the purpose of estimating our reserves as part of our year-end reporting process. As a result of that evaluation, we may increase or decrease the estimates of our reserves. We do not consider an increase or decrease in the estimates of our reserves in the range of up to five percent to be material or inconsistent with normal industry practice. Any significant reduction to the estimates of our reserves resulting from any such evaluation could have a material adverse effect on the value of our Trust Units.

If we are unable to acquire additional reserves, the value of the Trust Units and distributions to our Unitholders may decline.

Our future oil and natural gas reserves and production, and therefore the cash flows of the Trust, will depend upon our success in acquiring and/or developing additional reserves. If we fail to add reserves by acquiring or developing them, our reserves and production will decline over time as current reserves are produced. When reserves from our properties can no longer be economically produced and marketed, our Trust Units will have no value unless additional reserves have been acquired or developed. If we are not able to raise capital on favourable terms, we may not be able to add to or maintain our reserves. If we use our cash flow to acquire or develop reserves, we will reduce our cash available to be distributed to Unitholders. There is strong competition in all aspects of the oil and gas industry, including reserve acquisitions. We will actively compete for reserve acquisitions and skilled industry personnel with other oil and gas companies and energy trusts. However, we cannot assure you that we will be successful in acquiring additional reserves on terms that meet our objectives.

Continued uncertainty in the credit markets may restrict the availability or increase the cost of borrowing required for future development and acquisitions.

Continued uncertainty in domestic and international credit markets could materially affect our ability to access sufficient capital for our capital expenditures and acquisitions and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Unitholders.

In the normal course of our business, we have entered into contractual arrangements with third parties that subject us to the risk that such parties may default on their obligations.

We are exposed to third party credit risk through our contractual arrangements with current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from operations. In addition, 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 operation of oil and natural gas wells could subject us to potential environmental claims and liabilities, which will be funded out of our cash flow and will reduce cash flow otherwise available for distribution to Unitholders.

The oil and natural gas industry is subject to extensive environmental regulation, which imposes restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and gas industry operations. In addition, Canadian legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of this or other legislation may result in fines or the issuance of a clean-up order. Ongoing environmental obligations will be funded out of our cash flow and could therefore reduce the cash available to be distributed to our Unitholders.

We may be unable to successfully compete with other industry participants, which could negatively affect the market price of the Trust Units and distributions to our Unitholders.

There is strong competition in all aspects of the oil and gas industry. We will actively compete for capital, skilled personnel, undeveloped lands, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a world-wide basis and, as such, have greater technical, financial and operational resources than Pengrowth.

We have recently announced significant changes to our value creation strategy and have made and are making significant changes in our senior management. There can be no assurance that management will be successful in implementing our revised value creation strategy or that the intended benefits of our strategy will be realized to create value for our securityholders.

Incorrect assessments of value at the time of acquisitions could adversely affect the value of our Trust Units and distributions to our Unitholders.

Acquisitions of oil and gas properties or companies are 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 geologic and engineering uncertainty which could result in lower than anticipated production and reserves.

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

We are indebted under the Credit Facility, the 2003 U.S. Senior Notes, the 2007 U.S. Senior Notes, the 2008 Senior Notes and the U.K. Senior Notes. Certain covenants in the agreements with our lenders may limit the amount of distributions paid to Unitholders. See *Distributions Restrictions on Distributions* . Variations in interest rates, exchange rates and scheduled principal repayments could result in significant changes in the amount we are required to apply to the service of our outstanding indebtedness. If we become unable to pay our debt service charges or otherwise cause an event of default to occur, our lenders may foreclose on, or sell, our properties. The net proceeds of any such sale

Table of Contents

will be allocated firstly to the repayment of our lenders and other creditors and only the remainder, if any, would be payable to the Trust by the Corporation. In addition, we may not be able to refinance some or all of these debt obligations through the issuance of new debt obligations on the same terms, and we may be required to refinance through the issuance of new debt obligations on less favorable terms or through the issuance of additional securities or through other means. In any such event, the amount of cash available for distribution may be diluted or adversely impacted and such dilution or impact may be significant.

We are dependent on our management and the loss of our key management and other personnel could negatively impact our business.

Our Unitholders are entirely dependent on the management of the Corporation with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to properties and the administration of Pengrowth. The loss of the services of key individuals who currently comprise our management team could have a detrimental effect on Pengrowth. In addition, increased activity within the oil and gas sector can increase the cost of goods and services and make it more difficult to attract and retain qualified professional staff.

A decline in our ability to market our oil and natural gas production could have a material adverse effect on production levels or on the price received for production, which, in turn, could reduce distributions to our Unitholders and affect the market price of the Trust Units.

The marketability of our production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. United States federal and state and Canadian federal and provincial regulation of oil and gas production and transportation, general economic conditions, and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on us could be substantial. The availability of markets is beyond our control.

The operation of a portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues, which could negatively affect the market price of the Trust Units and distributions to our Unitholders.

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately 45 percent of our properties are operated by third parties, based on daily production. If, in situations where we are not the operator, the operator fails to perform these functions properly or becomes insolvent, revenues may be reduced. Revenues from production generally flow through the operator and, where we are not the operator; there is a risk of delay and additional expense in receiving such revenues. The operations of the wells located on properties not operated by us are generally governed by operating agreements which typically require the operator to conduct operations in a good and workman-like manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or willful misconduct. In addition, third-party operators are generally not fiduciaries with respect to Pengrowth or the Unitholders. As owner of working interests in properties not operated by it, we will generally have a cause of action for damages arising from a breach of the operator s duty. Although not established by definitive legal precedent, it is unlikely that we or our Unitholders would be entitled to bring suit against third-party operators to enforce the terms of the operating agreements. Therefore, our Unitholders will be dependent upon us, as owner of the working interest, to enforce such rights.

Table of Contents

Our distributions could be adversely affected by unforeseen title defects, which could reduce distributions to our Unitholders.

Although title reviews are conducted prior to any purchase of significant resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. Such defects could reduce the amounts distributable to our Unitholders, and could result in a reduction of capital.

Fluctuations in foreign currency exchange rates could adversely affect our business, the market price of the Trust Units and distributions to our Unitholders.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate which fluctuates over time. A material increase in the value of the Canadian dollar may negatively impact our net production revenue and cash flow. To the extent that we have engaged, or in the future engage, in risk management activities related to commodity prices and foreign exchange rates, through entry into oil or natural gas price commodity contracts and foreign exchange contracts or otherwise, we may be subject to unfavourable price changes and credit risks associated with the counterparties with which we contract.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

Being a limited purpose trust makes the Trust largely dependent upon the operations and assets of the Corporation. If the oil and natural gas reserves associated with the resource properties of the Corporation are not supplemented through additional development or the acquisition of oil and natural gas properties, our ability to continue to generate cash flow for distribution to Unitholders may be adversely affected.

The Trust is a limited purpose trust which is dependent upon the operations and assets of the Corporation. Our income will be received from the production of crude oil and natural gas from its properties and will be susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. Since the primary focus is to pursue growth opportunities through the development of existing reserves and the acquisition of new properties, our involvement in the exploration for oil and natural gas is minimal. As a result, if the oil and natural gas reserves associated with our resource properties are not supplemented through additional development or the acquisition of oil and natural gas properties, our ability to continue to generate cash flow for distribution to Unitholders may be adversely affected.

We may incur material costs as a result of compliance with health, safety and environmental laws and regulations which could negatively affect our financial condition and, therefore, reduce distributions to our Unitholders and decrease the market price of the Trust Units.

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with legislation and regulations to reduce emissions of GHGs into the air.

Lower oil and gas prices increase the risk of write-downs of our oil and gas property investments which could be viewed unfavourably in the market or could limit our ability to borrow funds or comply with covenants contained in our current or future credit agreements or other debt instruments.

Under Canadian accounting rules, the net capitalized cost of oil and gas properties may not exceed a ceiling limit which is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, we must charge the amount of the excess against earnings. As oil and gas prices decline, our net capitalized cost may approach and, in certain circumstances, exceed this cost ceiling, resulting in a charge against earnings. Under United States accounting rules, the cost ceiling is generally lower than under Canadian rules because the future net cash flows used in the United States ceiling test are based on proven reserves only. Accordingly, we would have more risk of a ceiling test write-down in a declining price environment if we reported under United States generally accepted accounting principles. While these write-downs would not affect cash flow, the charge to earnings could be viewed unfavourably in the market or could limit our ability to borrow funds or comply with covenants contained in our current or future credit agreements or other debt instruments.

Changes in Canadian legislation could adversely affect the value of our Trust Units.

The tax treatment of the Trust has a significant effect on the value of our Trust Units. We cannot assure you that income tax laws and government incentive programs relating to the oil and natural gas industry generally and the status of royalty trusts having our structure will not change in a manner that adversely affects your investment.

The SIFT Legislation has and may continue to materially and adversely affect Pengrowth, the Unitholders and the value of the Trust Units.

Should Pengrowth not convert to a dividend paying corporation, it is expected that the SIFT Legislation will subject the Trust to trust level taxation beginning on January 1, 2011, which will materially reduce the amount of cash available for distributions to the Unitholders. Based on the Canadian federal income tax rates and the expected provincial tax rates, we estimate that the SIFT Legislation will, commencing on January 1, 2011, reduce the amount of cash available to the Trust to distribute to its Unitholders. Under the current SIFT Legislation, the proposed tax is expected to be 26.5 percent in 2011 and 25 percent in 2012, assuming a provincial tax rate of ten percent being the applicable tax rate in the Province of Alberta where we anticipate 80 percent of our revenue will be generated in 2010. Subject to the availability of tax pools, the application of the SIFT Legislation will reduce the amount of cash available to the Trust to distribute to its Unitholders by an amount equal to 26.5 percent in 2011 (and by 25 percent in 2012 and thereafter) multiplied by the amount of the pre-tax income distributed by the Trust. A reduction in the value of the Trust Units would be expected to increase the cost to the Trust of raising capital in the public capital markets. In addition, the SIFT Legislation is expected to substantially eliminate the competitive advantage the Trust currently enjoys compared to corporate competitors in raising capital in a tax efficient manner, while placing the Trust at a competitive disadvantage compared to industry competitors, including U.S. master limited partnerships, which are expected to continue not to be subject to entity-level taxation. The SIFT Legislation is also expected to make the Trust Units less attractive as an acquisition currency. As a result, it may be more difficult for Pengrowth to compete effectively for acquisition opportunities in the future. There can be no assurance that Pengrowth will be able to reorganize its legal and tax structure to reduce the expected impact of the SIFT Legislation.

In addition, there can be no assurance that the Trust will be able to maintain its status as a grandfathered SIFT under the SIFT Legislation until 2011. If the Trust exceeds the limits on the issuance of new Trust Units and convertible debt that constitutes normal growth during the transitional period from October 31, 2006 to December 31, 2010, the SIFT Legislation would become effective on a date earlier than January 1, 2011.

Furthermore, we have announced our intention to convert to a dividend paying corporation prior to January 1, 2011. There can be no assurance that we will be able to complete our conversion by January 1, 2011 and in the event that we are unable to complete the conversion by that date, the SIFT Legislation will subject us to trust level taxation beginning on January 1, 2011.

If the Trust ceases to qualify as a mutual fund trust prior to the imposition of the SIFT Legislation it would adversely affect the value of our Trust Units.

It is intended that the Trust will at all times qualify as a mutual fund trust for the purposes of the Tax Act, subject to our intention to convert to a dividend paying corporation.

Notwithstanding the steps taken or to be taken by us, no assurance can be given that the status of the Trust as a mutual fund trust will not be challenged by a relevant taxation authority. If the Trust s status as a mutual fund trust is determined to have been lost, certain negative tax consequences will have resulted for the Trust and its Unitholders. These negative tax consequences include the following:

The Trust Units would cease to be a qualified investment for trusts governed by RRSPs, RRIFs, RESPs and DPSPs, as defined in the Tax Act. Where, at the end of a month, a RRSP, RRIF, RESP or DPSP holds Trust Units that ceased to be a qualified investment, the RRSP, RRIF, RESP or DPSP, as the case may be, must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1 percent of the fair market value of the Trust Units at the time such Trust Units were acquired by the RRSP, RRIF, RESP or DPSP. In addition, trusts governed by a RRSP or a RRIF which hold Trust Units that are not qualified investments will be subject to tax on the income attributable to the Trust Units while they are non-qualified investments, including the full capital gains, if any, realized on the disposition of such Trust Units. Where a trust governed by a RRSP or a RRIF acquires Trust Units that are not qualified investments, the value of the investment will be included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Trust Units that are not qualified investments can have their registration revoked by the Canada Revenue Agency.

The Trust would be required to pay a tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders, including non-resident persons and residents of Canada who are exempt from Part I tax.

The Trust would not be entitled to use the capital gains refund mechanism otherwise available for mutual fund trusts.

The Trust Units would constitute taxable Canadian property for the purposes of the Tax Act, potentially subjecting non-residents of Canada to tax pursuant to the Tax Act on the disposition (or deemed disposition) of such Trust Units.

Changes to accounting policies, including the implementation of IFRS, may result in significant adjustments to our financial results, which could negatively impact our business, including increasing the risk of failing a financial covenant contained within our Credit Facility.

In January 2006, the CICA Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that IFRS will replace Canadian GAAP in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated. The implementation of IFRS may result in significant adjustments to our financial results, which could negatively impact our business, including increasing the risk of failing a financial covenant contained within our Credit Facility. At this time, we cannot reasonably quantify the full impact that adopting IFRS will have on our financial position and future results. See *Distributions Restrictions on Distributions Revolving Credit Facility* .

The ability of investors resident in the United States to enforce civil remedies may be negatively affected for a number of reasons.

The Trust is an Alberta trust and the Corporation is an Alberta corporation. Both the Trust and the Corporation have their principal places of business in Canada. The majority of the directors and officers of the Corporation are residents of Canada and all or a substantial portion of the assets of such persons and of Pengrowth are located outside of the United States. Consequently, it may be difficult for United States investors

Table of Contents

to affect service of process within the United States upon Pengrowth or such persons or to realize in the United States upon judgments of courts of the United States predicated upon civil remedies under the United States *Securities Act of 1933*, as amended. Investors should not assume that Canadian courts:

will enforce judgments of United States courts obtained in actions against Pengrowth or such persons predicated upon the civil liability provisions of the United States federal securities laws or the securities or blue sky laws of any state within the United States; or

will enforce, in original actions, liabilities against Pengrowth or such persons predicated upon the United States federal securities laws or any such state securities or blue sky laws.

Your rights as a Unitholder differ from the rights associated with other types of investments and we cannot assure you that the distributions you receive over the life of your investment will meet or exceed your initial capital investment.

Trust Units should not be viewed by investors as shares in the Corporation. Trust Units are also dissimilar to conventional debt instruments in that there is no principal amount owing to our Unitholders. Trust Units represent a fractional interest in the Trust. Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The Trust s assets are royalty units of, net profits interests in, indebtedness and common shares of, the Corporation, as well as certain facilities interests, and may also include certain other investments permitted under the Trust Indenture. The trading price of our Trust Units is a function of, among other things, anticipated cash flow, the oil and natural gas properties acquired by us and the ability to effect long-term growth in the value of Pengrowth. The market price of the Trust Units is sensitive to a variety of market conditions including, but not limited to, interest rates and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of our Trust Units.

Our Trust Units will have no value when reserves from the properties can no longer be economically produced or marketed; as a result, cash distributions do not represent a yield in the traditional sense as they represent both return of capital and return on investment. Unitholders will have to obtain the return of capital invested out of cash flow derived from their investments in the Trust Units during the period when reserves can be economically recovered. Accordingly, we give no assurances that the distributions you receive over the life of your investment will meet or exceed your initial capital investment.

Future acquisitions may result in substantial future dilution of your Trust Units.

One of our objectives is to continually add to our reserves through acquisitions and through development. Our success is, in part, dependent on our ability to raise capital from time to time. Unitholders may also suffer dilution in connection with future issuance of Trust Units.

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.

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

Table of Contents

We include herein estimates of Proved, Proved Plus Probable and Possible Reserves, as well as Contingent Resources. The SEC permits, but does not require, the inclusion of estimates of probable and possible reserves in filings made with it by United States oil and gas companies. The SEC does not permit the inclusion of estimates of Contingent Resources in reports filed with it by United States companies.

You may be required to pay taxes even if you do not receive any cash distributions.

You may be required to pay federal income taxes and, in some cases, state, provincial and local income taxes on your share of our taxable income even if you do not receive any cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that result from your share of our taxable income.

Unitholders who are United States persons face certain income tax risks.

The United States federal income tax risks related to owning and disposing of our Trust Units include the following:

A non-United States entity treated as a corporation for United States federal income tax purposes will be a PFIC if it generates primarily passive income or the greater part of its assets generate, or are held for the production of, passive income. We currently believe that we are not a PFIC although no assurance can be given that we will not be a PFIC in 2010 or thereafter. If we were classified as a PFIC, for any year during which a United States Unitholder owns Trust Units, such United States Unitholder would generally be subject to special adverse rules including taxation at maximum ordinary income rates plus an interest charge on both gains on sale and certain dividends. Certain elections may be available to a United States Unitholders if we were classified as a PFIC to alleviate these adverse tax consequences.

Qualified dividend income received from the Trust before January 1, 2011 will be subject to a maximum rate of United States federal income tax of 15 percent to a United States Holder that is not a corporation, including an individual. This preferred rate may not be extended beyond December 31, 2010.

Changes in government regulations that affect the crude oil and natural gas industry could adversely affect us and reduce our distributions to our Unitholders.

The oil and gas industry in Canada is subject to federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas or increase our costs, either of which would have a material adverse impact on Pengrowth.

Table of Contents

Terrorist attacks and the threat of terrorist attacks may have an adverse impact on Pengrowth.
Energy sector participants, including Pengrowth, are a potential target for terrorists. The possibility that infrastructure facilities may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures as a precaution against possible terrorist attacks will result in increased cost to our business.

Delays in business operations could adversely affect the Trust s distributions to Unitholders and the market price of the Trust Units.
In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to Unitholders in a given period and expose us to additional third party credit risks.

Changes in market-based factors may adversely affect the trading price of the Trust Units.
The market price of our Trust Units is sensitive to a variety of market based factors including, but not limited to, interest rates, foreign exchange rates and the comparability of the Trust Units to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Trust Units.

The limited liability of Unitholders is uncertain.
Notwithstanding the fact that Alberta has adopted legislation purporting to limit Unitholder liability, because of uncertainties in the law relating to investment trusts, there is a risk that a Unitholder could be held personally liable for our obligations in respect of contracts or undertakings which we enter into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities. We have structured Pengrowth and attempted to conduct its business in a manner which mitigates its liability exposure and where possible, limits its liability to Trust property. However, such protective actions may not completely avoid Unitholder liability. Notwithstanding our attempts to limit Unitholder liability, Unitholders may not be protected from our liabilities to the same extent that a shareholder is protected from the liabilities of a corporation. Further, although we have agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of the Unitholder not having limited liability, we cannot assure prospective investors that any assets would be available in these circumstances to reimburse Unitholders for any such liability. Legislation that purports to limit Unitholder liability has been implemented in Alberta but there is

no assurance that such legislation will eliminate all risk of Unitholder liability. Additionally, the legislation does not affect the liability of Unitholders with respect to any act, default, obligation or liability that arose prior to July 1, 2004.

The redemption right of Unitholders is limited.

Unitholders have a limited right to require us to repurchase Trust Units, which is referred to as a redemption right. See *Description of Trust Units Redemption Right*. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. Our ability to pay cash in connection with a redemption is subject to limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance.

Our operations are subject to all of the risks normally associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells and the production and transportation of oil and natural gas. These risks and hazards include encountering unexpected formations or pressures, blow-outs, craterings and fires, all of which could result in personal injury, loss of life or environmental and other damage to our property and the property of others. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. While we have both safety and environmental policies in place to protect our operators and employees and to meet regulatory requirements in areas where we operate, any costs incurred to repair damages or pay liabilities would reduce the funds available for distribution to the Unitholders.

Table of Contents

MARKET FOR SECURITIES

Our Trust Units are listed on the TSX and the NYSE under the symbols PGF.UN and PGH , respectively.

	Toronto Stock Exchange Trust Unit Price Range				New York Stock Exchange Trust Unit Price Range			
	High	Low	Close	Volume	High	Low	Close	Volume
	(Canadian $ per Trust Unit)				(U.S. $ per Trust Unit)			
2009								
January	12.33	9.24	10.15	8,358,692	10.11	7.40	8.31	28,890,238
February	10.49	6.33	7.26	8,912,881	8.57	5.07	5.64	29,011,962
March	8.15	5.84	7.10	13,292,672	6.67	4.51	5.58	32,749,969
April	8.13	6.71	7.75	7,903,867	6.82	5.30	6.57	22,218,019
May	9.75	7.71	9.50	10,671,708	8.85	6.39	8.76	31,814,565
June	9.81	8.68	9.18	8,358,692	9.00	7.50	7.90	28,810,956
July	9.09	7.49	8.78	7,701,403	8.39	6.43	8.23	28,337,061
August	9.77	8.85	9.40	7,476,432	9.01	8.21	8.62	21,763,092
September	11.33	8.95	11.33	13,588,246	10.54	8.08	10.51	31,307,977
October	11.39	9.60	10.26	23,603,708	10.61	8.80	9.20	47,559,265
November	10.52	9.76	10.13	8,142,095	10.04	9.04	9.61	22,417,294
December	10.42	9.40	10.15	10,736,778	9.94	8.88	9.63	26,691,909

Prior to January 15, 2010, the Debentures were listed on the TSX under the symbol PGF.DB .

	Toronto Stock Exchange Debenture Price Range			
	High	Low	Close	Volume
	(Canadian $ per Debenture)			
2009				
January	97.00	93.00	96.50	746,150
February	96.25	91.50	95.75	1,079,000
March	95.50	90.00	93.00	912,000
April	95.00	92.00	95.00	7,555,000
May	99.95	94.50	99.55	3,083,150
June	100.00	99.50	100.00	3,468,000
July	101.50	99.60	100.50	2,540,000
August	102.00	100.65	101.50	742,000
September	102.99	100.70	101.85	1,310,000
October	102.00	101.50	101.50	1,623,000
November	102.75	101.50	102.75	925,000
December	102.99	102.00	102.25	1,342,000

On January 15, 2010, the Debentures were redeemed at a cash redemption price of $1,025 per $1,000 principal value for a total cost of $76,609,525 plus accrued and unpaid interest to the redemption date. See *Pengrowth Energy Trust Recent Developments Convertible Debentures* . The Debentures have subsequently been de-listed from the TSX.

Table of Contents

DIRECTORS AND OFFICERS

The Trust does not have any directors or officers. The following is a summary of information relating to the directors and officers respectively of the Corporation, the administrator of the Trust.

Directors and Officers of the Corporation

The name, jurisdiction of residence, position held and principal occupation of each director and officer of the Corporation are set out below:

Name and Jurisdiction of Residence	Position with Pengrowth Corporation	Principal Occupation	Trust Units Controlled or Beneficially Owned[1]
John B. Zaozirny[2][3] Alberta, Canada	Chairman and Director (Director since 1988)	Vice Chair Canaccord Capital Corporation	35,100
Derek W. Evans Alberta, Canada	President, Chief Executive Officer and Director (since 2009)	President and Chief Executive Officer Pengrowth Corporation	155,380
Thomas A. Cumming[3][4][5] Alberta, Canada	Director (since 2000)	Business Consultant	8,678
Wayne K. Foo[2][4] Alberta, Canada	Director (since 2006)	President and Chief Executive Officer Parex Resources Inc. (energy company)	4,273
James S. Kinnear Alberta, Canada	Chairman Emeritus and Director (since 1988)	President Kinnear Financial Limited	3,780,320
James D. McFarland[4][5] Alberta, Canada	Director (since 2010)	Business Consultant	
Michael S. Parrett[2][3][5] Ontario, Canada	Director (since 2004)	Business Consultant	4,000
A. Terence Poole[2][5] Alberta, Canada	Director (since 2005)	Business Consultant	40,000
D. Michael G. Stewart[3][4] Alberta, Canada	Director (since 2006)	Corporate Director	21,251
Nicholas C.H. Villiers London, England	Director (since 2007)	Business Consultant	
Douglas C. Bowles	Vice President and Controller	Vice President and	36,590

Alberta, Canada	(since March 1, 2006) Controller (since 2005)	Controller Pengrowth Corporation	
James E.A. Causgrove Alberta, Canada	Vice President, Production and Operations (since 2005)	Vice President, Production and Operations Pengrowth Corporation	75,015
William G. Christensen Alberta, Canada	Vice President, Strategic Planning and Reservoir Exploitation (since 2005)	Vice President, Strategic Planning and Reservoir Exploitation Pengrowth Corporation	56,514
James M. Donihee Alberta, Canada	Vice President and Chief of Staff (since 2007)	Vice President and Chief of Staff Pengrowth Corporation	36,607

Table of Contents

Name and Jurisdiction of Residence	Position with Pengrowth Corporation	Principal Occupation	Trust Units Controlled or Beneficially Owned[(1)]
Larry B. Strong Alberta, Canada	Vice President, Geosciences (since 2005)	Vice President, Geosciences Pengrowth Corporation	53,981
Christopher G. Webster Alberta, Canada	Chief Financial Officer (since 2005) Treasurer (2000 2005)	Chief Financial Officer Pengrowth Corporation	120,295

Notes:

(1) As at December 31, 2009 and excluding Trust Units issuable upon the exercise of outstanding rights or deferred entitlement units.

(1) Member of Corporate Governance Committee.

(2) Member of Compensation Committee.

(3) Member of Reserves, Operations and Environmental, Health and Safety Committee.

(4) Member of Audit Committee.

As at December 31, 2009, the foregoing directors and officers, as a group, beneficially owned, directly or indirectly, 4,428,004 Trust Units or approximately 1.53 percent of the issued and outstanding Trust Units and held rights and deferred entitlement units to acquire a further 2,078,667 Trust Units. The information as to shares beneficially owned, not being within the knowledge of the Corporation, has been furnished by the respective individuals.

The term of each director expires at the next annual meeting of Unitholders.

Each of the foregoing directors and officers has had the same principal occupation for the previous five years except for Wayne Foo who was President and Chief Executive Officer of Petro Andina Resources Inc., the predecessor to Parex Resources Inc., from 2003 to 2009, Terry Poole who was Executive Vice President, Corporate Strategy and Development at Nova Chemicals Corporation from 2001 to 2006; James McFarland who was President and Chief Executive Officer and a Director of Verenex Energy Inc. from March 2004 until December 2009; Derek Evans who was President of Focus Energy Trust from 2002 to 2008; Chris Webster who was Vice President, Treasurer from September 30, 2004 to 2005; Larry Strong who was Vice President, Geosciences & Officer of Petrofund Corp. from 2004 to 2005; Bill Christensen who was Vice President, Planning of Northrock Resources from 2000 to 2005; Jim Causgrove who was Manager, New Growth Opportunities of Chevron Texaco Canada from 2003 to 2005; Doug Bowles who was Financial Reporting Manager from 2003 to 2005 of ExxonMobil Canada; and James Donihee who was Chief Operating Officer of the National Energy Board (Canada) from 2003 to 2007.

Corporate Cease Trade Orders or Bankruptcies

No director, executive officer or controlling security holder of Pengrowth is, as at the date of this Annual Information Form, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(ii)

was subject to an event that resulted, after the person ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(iii) 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.

Personal Bankruptcies

No director, executive officer or controlling security holder of Pengrowth has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person s assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of Pengrowth has:

(i) been subject to 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, other than penalties for late filing of insider reports; or

(ii) been subject to 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.

AUDIT COMMITTEE

The Audit Committee is appointed annually by the Board of Directors. The responsibilities and duties of the Audit Committee are set forth in the Audit Committee Terms of Reference attached hereto as Appendix C. The following table sets forth the name of each of the current members of the Audit Committee, whether such member is independent and financially literate, as those terms are defined in Multilateral Instrument 52-110 *Audit Committees*, and the relevant education and experience of each such member:

Name	Independent	Financially Literate	Relevant Education and Experience
Thomas A. Cumming	Yes	Yes	Mr. Cumming was President and Chief Executive Officer of the Alberta Stock Exchange from 1988 to 1999. His career also includes 25 years with a major Canadian bank both nationally and internationally. He is currently Chairman of Alberta s Electricity Balancing Pool, and serves as a Director of the Alberta Capital Market Foundation. He is also a past president of the Calgary Chamber of Commerce. Mr. Cumming is a professional engineer and holds a Bachelor of Applied Science degree in Engineering and Business from the University of Toronto.
James D. McFarland	Yes	Yes	Mr. McFarland has more than 37 years of experience in the oil and gas industry, most recently as President and CEO, director and co-founder of Verenex Energy Inc. He has served in senior executive roles as Managing Director of Southern Pacific Petroleum N.L. in Australia, President and Chief Operating Officer of Husky Oil Limited and in a wide range of upstream and corporate functions in an earlier 23-year career with Imperial Oil Limited and other Exxon affiliates in Canada, the US and western Europe. Mr. McFarland is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and the Society of Petroleum Engineers International. Mr. McFarland received a Bachelor of

Science in Chemical Engineering from Queen s University and a Master of Science in Petroleum Engineering from the University of Alberta.

Table of Contents

Name	Independent	Financially Literate	Relevant Education and Experience
Michael S. Parrett	Yes	Yes	Mr. Parrett is currently an independent consultant providing advisory service to various companies in Canada and the United States. Mr. Parrett is Chairman of Gabriel Resources Limited, a director of Stillwater Mining Company and until October 31, 2008 was a member of the board of Fording Inc. and served as a Trustee for Fording Canadian Coal Trust. He was formerly President of Rio Algom Limited and prior to that Chief Financial Officer of Rio Algom and Falconbridge Limited. Mr. Parrett is a chartered accountant and holds a Bachelor of Arts in Economics from York University.
A. Terence Poole	Yes	Yes	Mr. Poole brings extensive senior financial management, accounting, capital and debt market experience to Pengrowth. He retired from Nova Chemicals Corporation in 2006 where he had held various senior management positions including Executive Vice-President, Corporate Strategy and Development. Mr. Poole currently serves on the board of directors for Methanex Corporation. Mr. Poole received a Bachelor of Commerce degree from Dalhousie University and holds a Chartered Accountant designation.

Principal Accountant Fees and Services

The following table provides information about the aggregate fees billed to Pengrowth for professional services rendered by KPMG LLP during fiscal 2009 and 2008:

	2009	**2008**
Audit Fees	1,314	1,037
Audit Related Fees		
Tax Fees	208	98
All Other Fees		
Total	1,522	1,135

Audit Fees

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

Audit-Related Fees

Audit-related fees normally include due diligence reviews in connection with acquisitions, research of accounting and audit-related issues and the completion of audits required by contracts to which Pengrowth is a party.

Tax Fees

During 2009 and 2008 the services provided in this category included assistance and advice in relation to the preparation of income tax returns for Pengrowth and its subsidiaries, tax advice and planning and commodity tax consultation.

Pre-approval Policies and Procedures

Pengrowth has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The audit committee approves a schedule which summarizes the services to be provided that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit Committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of Pengrowth s management to make a judgment as to whether a

Table of Contents

proposed service fits within the pre-approved services. Services that arise that were not contemplated in the schedule must be pre-approved by the Audit Committee chairman or a delegate of the audit committee. The full Audit Committee is informed of the services at its next meeting.

Pengrowth has not approved any non-audit services on the basis of the *de minimis* exemptions. All non-audit services are pre-approved by the Audit Committee in accordance with the pre-approval policy referenced herein.

CONFLICTS OF INTEREST

The Board of Directors supervises the management of the business and affairs of the Corporation and the Trust. The Board of Directors makes significant operational decisions and all decisions relating to:

- the issuance of additional Trust Units;
- material acquisitions and dispositions of properties;
- material capital expenditures;
- borrowing; and
- the payment of distributable cash.

Properties may not be acquired from persons not at arm s length with the Corporation at prices which are greater than fair market value and properties may not be sold to persons not at arm s length with the Corporation at prices which are less than fair market value, in each case as established by an opinion of an independent financial advisor and approved by the independent members of the Board of Directors. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of Unitholders in accordance with the requirements of Multilateral Instrument 61-101 *Protection of Minority Security Holders in Special Transactions.*

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations which are in competition to the interests of the Corporation and the Trust. No assurances can be given that opportunities identified by such board members will be provided to the Corporation and the Trust.

LEGAL PROCEEDINGS

Pengrowth is sometimes named as a defendant in litigation. The nature of these claims is usually related to settlement of normal operational or labor issues. The outcome of such claims against Pengrowth are not determinable at this time, however they are not expected to have a materially adverse effect on Pengrowth as a whole. Pengrowth is not, and has not been at any time within the most recently completed financial year, a party to any legal proceedings, known or contemplated, where the damages involved, excluding interest and costs, exceed ten percent of Pengrowth s assets.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of directors, executive officers, senior officers, any direct or indirect Unitholder of Pengrowth who beneficially owns, or who exercises control over, more than 10 percent of the outstanding Trust Units or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect Pengrowth.

Mr. John Zaozirny, the Chairman of the Board of Directors, is the Vice Chair of Canaccord Capital Corporation. Canaccord Capital Corporation participated as a member of the syndicate of underwriters in connection with the October 23, 2009 equity offering by the Trust of 28,847,000 Trust Units and received a portion of the underwriters fee from the offering.

Table of Contents

INTERESTS OF EXPERTS

As of the date hereof, the partners and associates of Bennett Jones LLP, as a group, beneficially own, directly or indirectly, less than one percent of the outstanding Trust Units. As of the date hereof, the directors and officers of GLJ, as a group, beneficially own, directly or indirectly, less than one percent of the outstanding Trust Units.

KPMG LLP are the auditors of the Trust and have confirmed that they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Alberta Institute of Chartered Accountants.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Trust Units is Computershare Trust Company of Canada at its principal offices in the cities of Montreal, Toronto, Calgary and Vancouver in Canada and Computershare Trust Company, Inc. at its principal offices in the cities of New York, New York and Denver, Colorado in the United States. The auditors of the Trust are KPMG LLP, Chartered Accountants in Calgary, Alberta.

MATERIAL CONTRACTS

The only material contracts entered into by the Corporation or the Trust during the most recently completed financial year, or before the most recently completed financial year that is still in effect, other than during the ordinary course of business, are as follows:

1. Trust Indenture;

2. Royalty Indenture;

3. the Corporation s unanimous shareholder agreement;

4. the Fifth Amended and Restated Credit Agreement dated June 17, 2007 between Pengrowth and a syndicate of eleven financial institutions concerning the Credit Facility;

5. the Note Purchase Agreement dated August 21, 2008 concerning the 2008 Senior Notes;

6. the Note Purchase Agreement dated July 26, 2007 concerning the 2007 U.S. Senior Notes;

7. the Note Purchase Agreement dated December 1, 2005 concerning the U.K. Senior Notes;

8. the Note Purchase Agreement dated April 23, 2003 concerning the 2003 U.S. Senior Notes;

9. the Distribution Agreement; and

10. the underwriting agreement relating to the October 23, 2009 bought deal public offering of 28,847,000 Trust Units.

Copies of these contracts have been filed by the Trust on SEDAR and are available through the SEDAR website at www.sedar.com.

CODE OF ETHICS

Pengrowth has adopted a code of ethics, as that term is defined in Form 40-F under the *U.S. Securities Exchange Act of 1934* (the Code of Ethics) that applies to Pengrowth s management, including its Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Code of Ethics is available for viewing on our website www.pengrowth.com, under the name Code of Business Conduct and Ethics , and is available in print to any Unitholder who requests it.

Table of Contents

The Board of Directors approved changes to the Code of Ethics on November 11, 2009 in order to clarify that any retaliation against directors, officers, employees, consultants and contractors of Pengrowth who report possible violations of law or the Code of Ethics is prohibited and to make other clerical amendments. All employees are required to accept the Code annually.

During the year ended December 31, 2009, Pengrowth has not granted any waivers (including implicit waivers) from the Code of Ethics in respect of its Chief Executive Officer, Chief Financial Officer or its principal accounting officer.

OFF-BALANCE SHEET ARRANGEMENTS

Pengrowth has no off-balance sheet arrangements.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian reporting issuer with securities listed on the TSX, Pengrowth has in place a system of corporate governance practices which complies with Canadian securities laws and the TSX corporate governance guidelines as well as the corporate governance rules of the NYSE applicable to foreign private issuers. In the context of its listing on the New York Stock Exchange, Pengrowth is classified as a foreign private issuer and therefore only certain of the NYSE rules are applicable to Pengrowth. However, Pengrowth benchmarks its policies and procedures against major North American entities, with a view to adopting the best practices when appropriate to its circumstances.

The Board of Directors of the Corporation has formerly adopted and published a Corporate Governance Policy which affirms Pengrowth s commitment to maintaining a high standard of corporate governance. This policy is published on Pengrowth s website at www.pengrowth.com. The Board of Directors of the Corporation has also adopted an Audit Committee Charter, Corporate Governance Committee Terms of Reference, Compensation Committee Terms of Reference, Reserves, Operations and Environment, Health and Safety Committee Terms of Reference, a Code of Business Conduct, a Corporate Disclosure Policy, an Insider Trading Policy and a Whistle Blower Policy each of which is published on Pengrowth s website, and is available in print to any Unitholder who requests it. The Audit Committee Charter is also attached hereto as Appendix C. From time to time, special committees of the Board of Directors are formed with prescribed mandates.

There is only one significant way in which Pengrowth s corporate governance practices differ from those required to be followed by domestic United States issuers under the NYSE Listed Company Manual. The NYSE Listed Company Manual requires shareholder approval of all equity compensation plans and any material revisions to such plans, regardless of whether the securities to be delivered under such plans are newly issued or purchased on the open market, subject to a few limited exceptions. In contrast, the TSX rules require shareholder approval of equity compensation plans only when such plans involve newly issued securities. If the plan provides a procedure for its amendment, the TSX rules require shareholder approval of amendments only where the amendment involves a reduction in the exercise price or an extension of the term of options held by insiders. As a matter of practice, Pengrowth has obtained the approval of its Unitholders to all of its equity compensation plans, regardless of whether the Trust Units to be delivered under such plans are newly issued or purchased on the open market, with the exception of the Trust Unit Awards Plan which has been used as an employee retention and hiring mechanism when required by the tight employment market in the Canadian oil and gas industry.

ADDITIONAL INFORMATION

Additional information, including directors and officers remuneration, the Manager s remuneration, the principal holders of Trust Units and securities authorized for issuance under equity compensation plans, is contained in Pengrowth s Management Information Circular dated May 5, 2009, which relates to the Annual and Special Meeting of Unitholders held on June 9, 2009. Pengrowth s next meeting of Unitholders is scheduled to take place in the second quarter of 2010. A current management information circular will be prepared and distributed not

Table of Contents

less than 20 days before the date of such meeting. Additional financial information is contained in the Trust s comparative consolidated financial statements and associated management s discussion and analysis for the years ended December 31, 2009 and 2008, which are included in the Trust s Annual Report for the year ended December 31, 2009.

Additional information relating to Pengrowth Energy Trust may be found on SEDAR at www.sedar.com.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Investor Relations
Pengrowth Energy Trust
Suite 2100, 222 3rd Avenue S.W.
Calgary, Alberta T2P 0B4
Telephone: (403) 233-0224
(888) 744-1111
Fax: (866) 341-3586
Website: www.pengrowth.com
E-mail: investorrelations@pengrowth.com

Table of Contents

APPENDIX A TO AIF
Report On Reserves Data By Independent
Qualified Reserves Evaluator On Form 51-101F2

Table of Contents

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Pengrowth Corporation (the Company):

1. We have prepared an evaluation of the Company s reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company s board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10 percent discount rate - $MM)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	January 15, 2010	Canada		$ 4,885		$ 4,885

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

the COGE Handbook.

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

Table of Contents

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 5, 2010.

(signed) *Doug R. Sutton*
Doug R. Sutton, P.Eng.
Vice-President

Table of Contents

APPENDIX B TO AIF
Report Of Management And Directors On Oil And Gas Disclosure On Form 51-101F3

Table of Contents

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
RESERVES DATA AND OTHER INFORMATION

Management of Pengrowth Corporation (the Company) are responsible for the preparation and disclosure of information with respect to the oil and gas activities of Pengrowth Energy Trust (the Pengrowth Trust) 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, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company s reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves, Operations and Environmental, Health and Safety Committee of the board of directors of the Company has

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

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

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

The Reserves, Operations and Environmental, Health and Safety Committee of the board of directors has reviewed the Company 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, Operations and Environmental, Health and Safety Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

/s/ Derek W. Evans
Derek W. Evans
President and Chief Executive Officer
Pengrowth Corporation

/s/ William G. Christensen
William G. Christensen
Vice President, Strategic Planning and Reservoir Exploitation
Pengrowth Corporation

/s/ Wayne Foo
Wayne Foo
Director
Pengrowth Corporation

/s/ D. Michael G. Stewart
D. Michael G. Stewart
Director
Pengrowth Corporation

March 8, 2010

Table of Contents

APPENDIX C TO AIF
Audit Committee Terms of Reference

Table of Contents

TERMS OF REFERENCE
AUDIT COMMITTEE
PENGROWTH CORPORATION
PENGROWTH ENERGY TRUST

Objectives

The Audit Committee is appointed by the board of directors (the Board) of Pengrowth Corporation (the Corporation) to assist the Board in fulfilling its oversight responsibilities. The Corporation is the administrator of Pengrowth Energy Trust (the Trust), an unincorporated energy investment trust settled pursuant to the terms of an amended and restated trust indenture originally dated December 2, 1988 and amended and restated July 1, 2009 (the Trust Indenture). The Trust and the Corporation, together with any subsidiaries or affiliates of the Trust, are collectively referred to as Pengrowth .

The Audit Committee s primary duties and responsibilities are to:

- monitor the performance of Pengrowth s internal audit function and the integrity of Pengrowth s financial reporting process and systems of internal controls regarding finance, accounting, and legal compliance;

- assist Board oversight of: (i) the integrity of Pengrowth s financial statements; (ii) Pengrowth s compliance with legal and regulatory requirements; and (iii) the performance of Pengrowth s internal audit function and independent auditors;

- monitor the independence, qualification and performance of Pengrowth s external auditors; and

- provide an avenue of communication among the external auditors, the internal auditors, management and the Board.

The Audit Committee will continuously review and modify its terms of reference with regards to, and to reflect changes in, the business environment, industry standards on matters of corporate governance, additional standards which the Audit Committee believes may be applicable to Pengrowth s business, the location of Pengrowth s business and its unitholders and the application of laws and policies.

Composition

Audit Committee members must meet the requirements of applicable securities laws and each of the stock exchanges on which the units of the Trust trade. The Audit Committee will be comprised of three or more directors as determined by the Board. Each member of the Audit Committee shall be independent and financially literate , as those terms are defined in National Instrument 52-110 *Audit Committees* (NI 52-110) of the Canadian Securities Administrators (as set out in Schedule A hereto), Rule 10A-3 promulgated under the *Securities Exchange Act of 1934* (as set out in Schedule B hereto), and Section 303A.02 of the New York Stock Exchange Listed Company Manual (as set out in Schedule C hereto), as applicable, and as financially literate is interpreted by the Board in its business judgement. In addition, at least one member of the Audit Committee must have accounting or related financial management expertise as defined by paragraph (8) of general instruction B to Form 40-F and as interpreted by the Board in its business judgement.

Audit Committee members shall be appointed annually by the Board. The chair of the Audit Committee shall be appointed by the Board. If an Audit Committee chair is not designated or present, the members of the Audit Committee may designate a chair by majority vote of the Audit Committee membership.

Table of Contents

Meetings and Minutes

The Audit Committee shall meet at least four times annually, or more frequently if determined necessary to carry out its responsibilities.

A meeting may be called by any member of the Audit Committee or the Board Chairman or the Chief Executive Officer (CEO) of the Corporation. A notice of time and place of every meeting of the Audit Committee shall be given in writing to each member of the Audit Committee at least two business days prior to the time fixed for such meeting, unless notice of a meeting is waived by all members entitled to attend. Attendance of a member of the Audit Committee at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

A quorum for meetings of the Audit Committee shall require a majority of its members present in person or by telephone. If the chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting will be chosen to preside by a majority of the members of the Audit Committee present at that meeting.

The Board Chairman and the President and CEO of the Corporation shall be available to advise the Audit Committee, shall receive notice of meetings and may attend meetings of the Audit Committee at the invitation of the chair. Other management representatives, as well as Pengrowth s internal and external auditors, may be invited to attend as necessary. Notwithstanding the foregoing, the chair of the Audit Committee shall hold *in camera* sessions, without management present, at every meeting of the Committee.

Decisions of the Audit Committee shall be determined by a majority of the votes cast.

The Audit Committee shall appoint a member of the Audit Committee or other officer of Pengrowth to act as secretary at each meeting for the purpose of recording the minutes of each meeting.

The Audit Committee shall provide the Board with a summary of all meetings together with a copy of the minutes from such meetings. Where minutes have not yet been prepared, the chair shall provide the Board with oral reports on the activities of the Audit Committee. All information reviewed and discussed by the Audit Committee at any meeting shall be referred to in the minutes and made available for examination by the Board upon request to the chair.

Scope, Duties and Responsibilities

Mandatory Duties

<u>Review Procedures</u>

Pursuant to the requirements of NI 52-110 and other applicable laws, the Audit Committee will:

1. Review and reassess the adequacy of the Audit Committee s Terms of Reference at least annually, submit the Terms of Reference to the Board for approval and have the document published annually in the Trust s annual information circular and at least every three years in accordance with the regulations of the United States Securities and Exchange Commission.

2. Prior to filing or public distribution, review, discuss with management and the internal and external auditors and recommend to the Board for approval, Pengrowth s audited annual financial statements, annual earnings press releases, annual information form, all statements including the related management s discussion and analysis required in prospectuses and other offering memoranda, financial statements required by regulatory authorities, all prospectuses and all documents which may be incorporated by reference into a prospectus, including without limitation, the annual information circular. Approve, on behalf of the Board, Pengrowth s interim financial statements

and related management s discussion and analysis and interim earnings press releases. This review should include discussions with management, the internal auditors and the external auditors of significant issues regarding accounting principles, practices and judgements. Discuss any significant changes to Pengrowth s accounting principles and any items required to be communicated by the external auditors in accordance with Assurance and Related Services Guideline #11 (AuG-11).

3. Ensure that adequate procedures are in place for the review of Pengrowth s public disclosure of financial information extracted or derived from Pengrowth s financial statements, other than the public disclosure referred to in paragraph 2 above and periodically assess the adequacy of those procedures.

4. Be responsible for reviewing the disclosure contained in Pengrowth s annual information form as required by Form 52-110F1 *Audit Committee Information Required in an AIF*, attached to NI 52-110. If proxies are solicited for the election of directors of the Corporation, the Audit Committee shall be responsible for ensuring that Pengrowth s information circular includes a cross-reference to the sections in Pengrowth s annual information form that contain the information required by Form 52-110F1.

External Auditors

1. The Audit Committee shall advise the external auditors of their accountability to the Audit Committee and the Board as representatives of the unitholders of the Trust to whom the external auditors are ultimately responsible. The external auditors shall report directly to the Audit Committee. The Audit Committee is directly responsible for overseeing the work of the external auditors, shall review at least annually the independence and performance of the external auditors and shall annually recommend to the Board the appointment of the external auditors or approve any discharge of auditors when circumstances warrant. The Audit Committee shall, on an annual basis, obtain and review a report by the external auditor describing: (i) the external auditor s internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the external 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 external auditors, and any steps taken to deal with any such issues; and (iii) all relationships between the independent auditor and Pengrowth.

2. Approve the fees and other compensation to be paid to the external auditors.

3. Pre-approve all services to be provided to Pengrowth or its subsidiary entities by Pengrowth s external auditors and all related terms of engagement.

Other Audit Committee Responsibilities

1. Establish procedures for: (i) the receipt, retention and treatment of complaints received by Pengrowth regarding accounting, internal accounting controls, or auditing matters; and (ii) the confidential and anonymous submission by employees of Pengrowth of concerns regarding questionable accounting or auditing matters.

2. Review and approve Pengrowth s hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of Pengrowth.

Discretionary Duties

The Audit Committee s responsibilities may, at the Audit Committee s discretion, also include the following:

Review Procedures

1. In consultation with management, the internal auditors and the external auditors, consider the integrity of Pengrowth s financial reporting processes and controls and the performance of Pengrowth s internal financial accounting staff; discuss significant financial risk exposures and the steps management has taken to monitor, control and report such exposures; and review significant findings prepared by the internal or external auditors together with management s responses.

2. Review, with financial management, the internal auditors and the external auditors, Pengrowth s policies relating to risk management and risk assessment.

3. Meet separately with each of management, the internal auditors and the external auditors to discuss difficulties or concerns, specifically: (i) any difficulties encountered in the course of the audit work, including any restrictions on the scope of activities or access to requested information, and any significant disagreements with management; (ii) any changes required in the planned scope of the audit; and (iii) the responsibilities, budget, and staffing of the internal audit function, and report to the Board on such meetings.

4. Conduct an annual performance evaluation of the Audit Committee.

Internal Auditors

1. Review the annual audit plans of the internal auditors.

2. Review the significant findings prepared by the internal auditors and recommendations issued by any external party relating to internal audit issues, together with management s response.

3. Review the adequacy of the resources of the internal auditors to ensure the objectivity and independence of the internal audit function.

4. Consult with management on management s appointment, replacement, reassignment or dismissal of the internal auditors.

5. Ensure that the internal auditors have access to the Board Chairman and the President and CEO.

External Auditors

1. On an annual basis, the Audit Committee should review and discuss with the external auditors all significant relationships they have with Pengrowth that could impair the auditors independence.

2. The Audit Committee shall review the external auditors audit plan discuss scope, staffing, locations, and reliance upon management and general audit approach.

3. Consider the external auditors judgments about the quality and appropriateness of Pengrowth s accounting principles as applied in its financial reporting.

4. Be responsible for the resolution of disagreements between management and the external auditors regarding financial performance.

5. Ensure compliance by the external auditors with the requirements set forth in National Instrument 52-108 *Auditor Oversight*.

6. Ensure that the external auditors are participants in good standing with the Canadian Public Accountability Board (CPAB) and participate in the oversight programs established by the CPAB from time to time and that the external auditors have complied with any restrictions or sanctions imposed by the CPAB as of the date of the applicable auditor s report relating to Pengrowth s annual audited financial statements.

7. Monitor compliance with the lead auditor rotation requirements of Regulation S-X.

Other Audit Committee Responsibilities

1. On at least an annual basis, review with Pengrowth s legal counsel any legal matters that could have a significant impact on the organization s financial statements, Pengrowth s compliance with applicable laws and regulations, and inquiries received from regulators or governmental agencies.

2. Annually prepare a report to unitholders as required by the United States Securities and Exchange Commission; the report should be included in Pengrowth s annual information circular.

3. Ensure due compliance with each obligation to certify, on an annual and interim basis, internal control over financial reporting and disclosure controls and procedures in accordance with applicable securities laws and regulations.

4. Review all exceptions to established policies, procedures and internal controls of Pengrowth, which have been approved by any two officers of the Corporation.

5. Perform any other activities consistent with this Charter, the Trust Indenture, the Corporation s by-laws, and other governing law as the Audit Committee or the Board deems necessary or appropriate.

6. Maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

Communication, Authority to Engage Advisors and Expenses

The Audit Committee shall have direct access to such officers and employees of Pengrowth, to Pengrowth s internal and external auditors and to any other consultants or advisors, as well as to such information respecting Pengrowth it considers necessary to perform its duties and responsibilities.

Any employee may bring before the Audit Committee, on a confidential basis, any concerns relating to matters over which the Audit Committee has oversight responsibilities.

The Audit Committee has the authority to engage the external auditors, independent legal counsel and other advisors as it determines necessary to carry out its duties and to set the compensation for any auditors, counsel and other advisors, such engagement to be at Pengrowth s expense. Pengrowth shall be responsible for all other expenses of the Audit Committee that are deemed necessary or appropriate by the Audit Committee in order to carry out its duties.

Adopted by the Board of the Corporation, in its capacity as administrator of the Trust, on November 11, 2009.

Table of Contents

A-1

Schedule A
Excerpt from Multilateral Instrument 52-110
Standard of Independence

1. An audit committee member is independent if he or she has no direct or indirect material relationship with Pengrowth.

2. For the purposes of paragraph 1, a material relationship is a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a member s independent judgment.

3. Despite paragraph 2, the following individuals are considered to have a material relationship with Pengrowth:
   (a) an individual who is, or has been within the last three years, an employee or executive officer of Pengrowth;

   (b) an individual whose immediate family member is, or has been within the last three years, an executive officer of Pengrowth;

   (c) an individual who:
      (i) is a partner of a firm that is Pengrowth s internal or external auditor,

      (ii) is an employee of that firm, or

      (iii) was within the last three years a partner or employee of that firm and personally worked on Pengrowth s audit within that time;
   (d) an individual whose spouse, minor child or stepchild, or child or stepchild who shares a home with the individual:
      (i) is a partner of a firm that is Pengrowth s internal or external auditor,

      (ii) is an employee of that firm and participates in its audit, assurance or tax compliance (but not tax planning) practice, or

      (iii) was within the last three years a partner or employee of that firm and personally worked on Pengrowth s audit within that time;
   (e) an individual who, or whose immediate family member, is or has been within the last three years, an executive officer of an entity if any of Pengrowth s current executive officers serves or served at that same time on the entity s compensation committee; and

   (f) an individual who received, or whose immediate family member who is employed as an executive officer of Pengrowth received, more than $75,000 in direct compensation from the issuer during any 12 month period within the last three years.
4. Despite paragraph 3, an individual will not be considered to have a material relationship with Pengrowth solely because he or she had a relationship identified in paragraph 3 if that relationship ended before March 30, 2004.

Table of Contents

A-2

5. For the purposes of paragraphs 3(c) and 3(d), a partner does not include a fixed income partner whose interest in the firm that is the internal or external auditor is limited to the receipt of fixed compensation (including deferred compensation) for prior service with that firm if the compensation is not contingent in any way on continued service.

6. For the purposes of paragraph 3(f), direct compensation does not include
   (a) remuneration for acting as a member of the Board or any Board committee of Pengrowth, and

   (b) the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with Pengrowth if the compensation is not contingent in any way on continued service.

7. Despite paragraph 3, an individual will not be considered to have a material relationship with Pengrowth solely because the individual or his or her immediate family member
   (a) has previously acted as an interim chief executive officer of Pengrowth, or

   (b) acts, or has previously acted, as a chair or vice-chair of the Board or of any Board committee of Pengrowth on a part-time basis.

8. Despite any determination made under paragraphs 1 through 7, an individual who
   (a) accepts, directly or indirectly, any consulting, advisory or other compensatory fee from Pengrowth, other than as remuneration for acting in his or her capacity as a member of the Board or any Board committee, or as a part-time chair or vice-chair of the Board or any Board committee; or

   (b) is an affiliated entity of Pengrowth or any of its subsidiary entities,

   is considered to have a material relationship with Pengrowth.

9. For the purposes of paragraph 8, the indirect acceptance by an individual of any consulting, advisory or other compensatory fee includes acceptance of a fee by
   (a) an individual s spouse, minor child or stepchild, or a child or stepchild who shares the individual s home; or

   (b) an entity in which such individual is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to Pengrowth.

10. For the purposes of paragraph 8, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with Pengrowth if the compensation is not contingent in any way on continued service.

Standard of Financial Literacy"

An individual is financially literate if he or she has 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 the issues that can reasonably be expected to be raised by Pengrowth s financial statements.

Table of Contents

B-1

Schedule B

Excerpts from Rule 10A-3 of the Securities and Exchange Act of 1934
Standard of Independence

b. *Required standards.*

1. *Independence*.
   i. Each member of the audit committee must be a member of the board of directors of the listed issuer, and must otherwise be independent; provided that, where a listed issuer is one of two dual holding companies, those companies may designate one audit committee for both companies so long as each member of the audit committee is a member of the board of directors of at least one of such dual holding companies.

   ii. *Independence requirements for non-investment company issuers.* In order to be considered to be independent for purposes of this paragraph (b)(1), a member of an audit committee of a listed issuer that is not an investment company may not, other than in his or her capacity as a member of the audit committee, the board of directors, or any other board committee:
      A. Accept directly or indirectly any consulting, advisory, or other compensatory fee from the issuer or any subsidiary thereof, provided that, unless the rules of the national securities exchange or national securities association provide otherwise, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the listed issuer (provided that such compensation is not contingent in any way on continued service); or

      B. Be an affiliated person of the issuer or any subsidiary thereof.

e. *Definitions*. Unless the context otherwise requires, all terms used in this section have the same meaning as in the Act. In addition, unless the context otherwise requires, the following definitions apply for purposes of this section:

1.
   i. The term *affiliate* of, or a person *affiliated* with, a specified person, means a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified.

   ii.
      A. A person will be deemed not to be in control of a specified person for purposes of this section if the person:
         1. Is not the beneficial owner, directly or indirectly, of more than 10% of any class of voting equity securities of the specified person; and

         2. Is not an executive officer of the specified person.
      B. Paragraph (e)(1)(ii)(A) of this section only creates a safe harbor position that a person does not control a specified person. The existence of the safe harbor does not create a presumption in any way that a person exceeding the ownership requirement in paragraph (e)(1)(ii)(A)(1) of this section controls or is otherwise an affiliate of a specified person.

Table of Contents

B-2

iii. The following will be deemed to be affiliates:
   A. An executive officer of an affiliate;

   B. A director who also is an employee of an affiliate;

   C. A general partner of an affiliate; and

   D. A managing member of an affiliate.

iv. For purposes of paragraph (e)(1)(i) of this section, dual holding companies will not be deemed to be affiliates of or persons affiliated with each other by virtue of their dual holding company arrangements with each other, including where directors of one dual holding company are also directors of the other dual holding company, or where directors of one or both dual holding companies are also directors of the businesses jointly controlled, directly or indirectly, by the dual holding companies (and, in each case, receive only ordinary-course compensation for serving as a member of the board of directors, audit committee or any other board committee of the dual holding companies or any entity that is jointly controlled, directly or indirectly, by the dual holding companies).

4. The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract, or otherwise.

8. The term indirect acceptance by a member of an audit committee of any consulting, advisory or other compensatory fee includes acceptance of such a fee by a spouse, a minor child or stepchild or a child or stepchild sharing a home with the member or by an entity in which such member is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the issuer or any subsidiary of the issuer.

Table of Contents

C-1

Schedule C

Excerpts from Rule 303A.00 of the New York Stock Exchange

303A.02 Independence Tests

The NYSE Listed Company Manual contains the following provisions regarding the independence requirements of members of the audit committee:

(a) No director qualifies as independent unless the board of directors affirmatively determines that the director has no material relationship with the listed company (either directly or as a partner, shareholder or officer of an organization that has a relationship with the company). Companies must identify which directors are independent and disclose the basis for that determination.

(b) In addition, a director is not independent if:

(i) The director is, or has been within the last three years, an employee of the listed company, or an immediate family member is, or has been within the last three years, an executive officer, of the listed company.

(ii) The director has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $120,000 in direct compensation from the listed company, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service).

(iii) (A) The director is a current partner or employee of a firm that is the company s internal or external auditor; (B) the director has an immediate family member who is a current partner of such a firm; (C) the director has an immediate family member who is a current employee of such a firm and personally works on the listed company s audit; or (D) the director or an immediate family member was within the last three years a partner or employee of such a firm and personally worked on the listed company s audit within that time.

(iv) The director or an immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of the listed company s present executive officers at the same time serves or served on that company s compensation committee.

(v) The director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the listed company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1 million, or 2% of such other company s consolidated gross revenues.

General Commentary to Section 303A.02(b):

An immediate family member includes a person s spouse, parents, children, siblings, mothers and fathers-in-law, sons and daughters-in-law, brothers and sisters-in-law, and anyone (other than domestic employees) who shares such person s home. When applying the look-back provisions in Section 303A.02(b), listed companies need not consider individuals who are no longer immediate family members as a result of legal separation or divorce, or those who have died or become incapacitated.

Table of Contents

C-2

For the purposes of Section 303A, the term executive officer has the same meaning specified for the term officer in Rule 16a-1(f) under the Securities Exchange Act of 1934 as follows:

The term officer shall mean an issuer s president, principal financial officer, principal accounting officer (or, if there is no such accounting officer, the controller), any vice-president of the issuer in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the issuer. Officers of the issuer s parent(s) or subsidiaries shall be deemed officers of the issuer if they perform such policy-making functions for the issuer. In addition, when the issuer is a limited partnership, officers or employees of the general partner(s) who perform policy-making functions for the limited partnership are deemed officers of the limited partnership. When the issuer is a trust, officers or employees of the trustee(s) who perform policy-making functions for the trust are deemed officers of the trust.

Table of Contents

APPENDIX B
MANAGEMENT S DISCUSSION AND ANALYSIS

Table of Contents

Summary of Financial & Operating Results

monetary amounts in thousands, except per unit amounts)	Three Months ended December 31 2009	2008	% Change	Twelve Months ended December 3 2009	2008	% Chan
TATEMENT OF INCOME						
il and gas sales	$359,296	$392,158	(8)	$1,343,167	$1,919,049	(30
et income	$ 50,523	$148,688	(66)	$ 84,853	$ 395,850	(79
et income per trust unit	$ 0.18	$ 0.58	(69)	$ 0.32	$ 1.58	(80
ASH FLOW						
ash flow from operating activities	$149,933	$154,807	(3)	$ 551,350	$ 912,516	(40
ash flow from operating activities per trust unit	$ 0.53	$ 0.61	(13)	$ 2.09	$ 3.65	(43
istributions declared	$ 60,880	$144,663	(58)	$ 287,853	$ 651,015	(56
istributions declared per trust unit	$ 0.21	$ 0.565	(63)	$ 1.08	$ 2.590	(58
atio of distributions declared over cash flow from perating activities	41%	93%		52%	71%	
apital expenditures	$ 46,215	$125,876	(63)	$ 207,451	$ 401,928	(48
apital expenditures per trust unit	$ 0.16	$ 0.49	(67)	$ 0.79	$ 1.61	(51
eighted average number of trust units outstanding (000 s)	282,298	255,473	11	264,121	250,182	6
ALANCE SHEET						
orking capital deficiency				$ (217,007) (1)	$ (70,159)	209
roperty, plant and equipment				$3,789,369	$4,251,381	(11
ong term debt				$ 907,599	$1,524,503	(40
rust unitholders equity				$2,795,201	$2,663,805	5
rust unitholders equity per trust unit				$ 9.64	$ 10.40	(7
urrency (U.S.$/Cdn$) (closing rate at period end)				0.9515	0.8210	
umber of trust units outstanding at period end (000 s)				289,835	256,076	13
VERAGE DAILY PRODUCTION						
rude oil (bbls)	21,948	24,236	(9)	22,841	24,416	(6
eavy oil (bbls)	7,235	8,217	(12)	7,551	8,122	(7
atural gas (mcf)	232,682	241,709	(4)	237,217	240,825	(1
atural gas liquids (bbls)	9,564	10,634	(10)	9,590	9,315	3
otal production (boe)	77,529	83,373	(7)	79,518	81,991	(3
OTAL PRODUCTION (mboe)	7,133	7,670	(7)	29,024	30,009	(3
RODUCTION PROFILE						
rude oil	28%	29%		29%	30%	
eavy oil	9%	10%		9%	10%	

Iatural gas			50%		48%			50%		49%
Iatural gas liquids			13%		13%			12%		11%
VERAGE REALIZED PRICES (after commodity risk nanagement)										
rude oil (per bbl)		$	75.79	$	65.87	15	$	72.36	$	77.78	(7
Ieavy oil (per bbl)		$	62.16	$	42.20	47	$	52.72	$	75.77	(30
Iatural gas (per mcf)		$	5.45	$	7.40	(26)	$	5.14	$	8.19	(37
Iatural gas liquids (per bbl)		$	54.52	$	43.87	24	$	42.12	$	70.67	(40
verage realized price per boe		$	50.35	$	50.34	0	$	46.19	$	62.76	(26
ROVED PLUS PROBABLE RESERVES										
rude oil (mbbls)								112,249		121,289	(7
Ieavy oil (mbbls)								27,724		27,728	0
Iatural gas (bcf)								757		852	(11
Iatural gas liquids (mbbls)								29,587		32,442	(9
otal oil equivalent (mboe)								295,734		323,463	(9
UMMARY OF TRUST UNIT TRADING										
IYSE PGH ($U.S.)										
	High	$	10.52	$	15.00		$	10.54	$	21.90
	Low	$	8.81	$	6.84		$	4.51	$	6.84
	Close	$	9.63	$	7.62		$	9.63	$	7.62
SX PGF.UN ($Cdn)										
	High	$	11.39	$	15.98		$	12.33	$	21.56
	Low	$	9.40	$	8.55		$	5.84	$	8.55
	Close	$	10.15	$	9.35		$	10.15	$	9.35

(1) Includes $157.5 million current portion of long term debt.

Note regarding currency: all figures contained within this report are quoted in Canadian dollars unless otherwise indicated.

3

Table of Contents

Management s Discussion & Analysis

The following Management s Discussion and Analysis (MD&A) of financial results should be read in conjunction with the audited consolidated Financial Statements for the year ended December 31, 2009 of Pengrowth Energy Trust and is based on information available to March 8, 2010.

Frequently Recurring Terms

For the purposes of this MD&A, we use certain frequently recurring terms as follows: the Trust refers to Pengrowth Energy Trust, the Corporation refers to Pengrowth Corporation, Pengrowth refers to the Trust and its subsidiaries and the Corporation on a consolidated basis and the Manager refers to Pengrowth Management Limited.

Pengrowth uses the following frequently recurring industry terms in this MD&A: bbls refers to barrels, mbbls refers to thousands of barrels, boe refers to barrels of oil equivalent, mboe refers to a thousand barrels of oil equivalent, mcf refers to thousand cubic feet, bcf refers to billion cubic feet, gj refers to gigajoule, mmbtu refers to million British thermal units and mwh refers to megawatt hour. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf of natural gas to one barrel of crude oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Advisory Regarding Forward-Looking Statements

This MD&A contains forward-looking statements within the meaning of securities laws, including the safe harbour provisions of Canadian securities legislation and the United States *Private Securities Litigation Reform Act of 1995*. Forward-looking information is often, but not always, identified by the use of words such as anticipate , believe , expect , plan , intend , forecast , target , project , guidance , may , will , should , could , estimate , suggesting future outcomes or language suggesting an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: reserves, 2010 production, the proportion of 2010 production of each product type, production additions from Pengrowth s 2010 development program, royalty obligations, 2010 operating expenses, future income taxes, goodwill, asset retirement obligations, taxability of distributions, remediation and abandonment expenses, capital expenditures, general and administration expenses, the portion of our future distributions anticipated to be taxable, the potential impact of the SIFT tax (as defined herein) on Pengrowth and our unitholders, our potential ability to shield our taxable income from income tax using our tax pools for a period of time following the implementation of the SIFT tax, our currently anticipated conversion to a dividend paying entity which will be taxable as a corporation for Canadian federal income tax purposes, and proceeds from the disposal of properties. Statements relating to reserves are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can profitably be produced in the future.

Forward-looking statements and information are based on Pengrowth s current beliefs as well as assumptions made by, and information currently available to, Pengrowth concerning general economic and financial market conditions, anticipated financial performance, business prospects, strategies, regulatory developments, including in respect of taxation, royalty rates and environmental protection, future capital expenditures and the timing thereof, future oil and natural gas commodity prices and differentials between light, medium and heavy oil prices, future oil and natural gas production levels, future exchange rates and interest rates, the proceeds of anticipated divestitures, the amount of future cash distributions paid by Pengrowth, the cost of expanding our property holdings, our ability to obtain labour and equipment in a timely manner to carry out development activities, our ability to market our oil and natural gas successfully to current and new customers, the impact of increasing competition, our ability to obtain financing on acceptable terms, our ability to add production and reserves through our development, exploitation and exploration activities and our proposed conversion to a dividend paying corporation. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; Pengrowth s ability to replace and expand oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; counterparty risk; compliance with environmental laws and regulations; changes in tax and royalty laws; the failure to qualify as a mutual fund trust; and Pengrowth s ability to access external sources of debt and equity capital; the implementation of International Financial Reporting Standards; and the implementation of greenhouse gas emissions legislation. Further information regarding these factors may be found under the heading Business Risks herein and under Risk Factors in Pengrowth s most recent Annual Information Form (AIF), and in Pengrowth s most recent consolidated financial statements, management information circular, quarterly reports, material change reports and news releases. Copies of the Trust s Canadian public filings are available on SEDAR at www.sedar.com. The Trust s U.S. public filings, including the Trust s most recent annual report form 40-F as supplemented by its filings on form 6-K, are available at www.sec.gov.

Pengrowth cautions that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Pengrowth, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A and Pengrowth does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by law. The forward-looking statements in this document are provided for the limited purpose of enabling current and potential investors to evaluate an investment in Pengrowth. Readers are cautioned that such statements may not be appropriate, and should not be used for other purposes.

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Critical Accounting Estimates

The financial statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period ended.

The amounts recorded for depletion and depreciation of property, plant and equipment, amortization of injectants, unit based compensation, goodwill and future taxes are based on estimates. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. The amounts recorded for the fair value of risk management contracts and the unrealized gains or losses on the change in fair value are based on estimates. The provision for asset retirement obligations is based on estimates affected by assumptions around timing and cost estimates for the related work activity. These estimates can change significantly from period to period. As required by National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, Pengrowth uses independent qualified reserve evaluators in the preparation of the annual reserve evaluations. By their nature, these estimates are subject to measurement uncertainty and changes in these estimates may impact the consolidated financial statements of future periods.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Certain of these estimates may change from period to period resulting in a material impact on Pengrowth s results of operations, financial position, and change in financial position. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions as determined by Pengrowth s independent reserves evaluators. A material change in the future costs or oil and gas prices may have a material affect on the results of the ceiling test calculation. In the event an impairment charge is warranted, it would be written off through net income in the period. The prices used in the ceiling test are disclosed in Note 6 to the annual consolidated financial statements. While the reserves and estimated future prices have changed over the past two years, the results of the ceiling tests have indicated a significant surplus over net book value. Please refer to the oil and gas disclosures in the AIF filed each year for detailed disclosure of reserves and future net revenue.

The impairment assessment of goodwill is based on the estimated fair value of Pengrowth s reporting units which is referenced to Pengrowth s trust unit price and the premium an arm s length party would pay to acquire all of the outstanding trust units. Under Canadian GAAP, goodwill is assessed for impairment in a two step process. In the first step, the total net assets are compared to Pengrowth s total market capitalization and any control premium that may be considered reasonable. If the total market capitalization is greater than the total net assets, goodwill is determined not to be impaired and no further assessment is required. A significant change in the market price of Pengrowth s trust units or the necessary control premium may have a material impact on the assessment of goodwill which may require quantification under Step 2. Pengrowth has never been required to quantify any impairment under Step 2. A sustained period of a low trust unit price could cause Pengrowth to quantify any impairment under Step 2, which may result in a material write-down.

In the second step of the impairment assessment of goodwill, the total market capitalization plus an estimate of a premium to obtain control of Pengrowth is compared to the fair value of Pengrowth s net assets. The fair values of assets except property, plant and equipment would be determined in accordance with the policies disclosed in Note 20 to the financial statements. The fair value of property, plant and equipment would be determined based on estimates of proved plus probable reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions as determined by Pengrowth s independent reserves evaluators. A material change in the future costs or oil and gas prices may have a material affect on the results of the quantification of any potential impairment.

Non-GAAP Financial Measures

This MD&A refers to certain financial measures that are not determined in accordance with GAAP in Canada or the United States. These measures do not have standardized meanings and may not be comparable to similar measures presented by other trusts or corporations. Measures such as operating netbacks do not have standardized meanings prescribed by GAAP. See the section of this MD&A entitled Operating Netbacks for a discussion of the calculation. Distributions can be compared to cash flow from operating activities in order to determine the amount, if any, of distributions financed through debt or short term borrowing. The current level of capital expenditures funded through retained cash, as compared to debt or equity, can also be determined when it is compared to the difference in cash flow from operating activities and distributions paid in the financing section of the Statement of Cash Flow.

Management monitors Pengrowth s capital structure using non-GAAP financial metrics. The two metrics are Total Debt to the trailing twelve months Earnings Before Interest, Taxes, Depletion, Depreciation, Amortization, Accretion, and other non-cash items (EBITDA) and Total Debt to Total Capitalization. Total Debt is the sum of working capital deficit, long term debt and convertible debentures as shown on the balance sheet, and Total Capitalization is the sum of Total Debt and Unitholder s equity. Management believes that targeting prudent ratios of these measures are reasonable given the size of Pengrowth, its capital management objectives, growth strategy, uncertainty of oil and gas commodity prices and additional margin required over the debt covenants.

If the ratio of Total Debt to trailing EBITDA reaches or exceeds certain levels, management would consider steps to reduce the ratio of Total Debt to trailing EBITDA. If the ratio of Total Debt to Total Capitalization reaches or exceeds certain levels, management would consider steps to improve the ratio while considering our debt financial covenant limits.

Non-GAAP Operational Measures

The reserves and production in this MD&A refer to Company Interest reserves or production that is Pengrowth s working interest share of production or reserves prior to the deduction of Crown and other royalties plus any Pengrowth owned royalty interest in production or reserves at the wellhead. Company interest is more fully described in Pengrowth s AIF.

When converting natural gas to equivalent barrels of oil within this MD&A, Pengrowth uses the industry standard of six mcf to one boe. Barrels of oil equivalent may be misleading, particularly if used in isolation; a conversion ratio of six mcf of natural gas to one boe is based on an energy equivalency conversion primarily and does not represent a value equivalency at the wellhead. Production volumes, revenues and reserves are reported on a company interest gross basis (before royalties) in accordance with Canadian practice.

Currency

All amounts are stated in Canadian dollars unless otherwise specified.

Table of Contents

OVERVIEW

	Three months ended			Twelve months ended	
	Dec 31, 2009	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Production (boe/d)	**77,529**	78,135	83,373	**79,518**	81,991
Net capital expenditures ($000 s)	**46,215**	44,047	125,876	**207,451**	401,928
Netback ($/boe)	**26.63**	24.72	26.23	**25.38**	34.78
Cash flows from operating activities ($000 s)	**149,933**	162,915	154,807	**551,350**	912,516
Net income ($000 s)	**50,523**	78,290	148,688	**84,853**	395,850
Included in net income:					
Realized gain (loss) on commodity risk management ($000 s)	**27,855**	43,406	21,021	**171,147**	(194,342)
Unrealized gain (loss) on commodity risk management ($000 s)	**(40,101)**	(5,609)	292,249	**(173,726)**	249,899
Unrealized foreign exchange gain (loss) on foreign denominated debt ($000 s)	**17,660**	89,960	(127,207)	**148,295**	(172,626)

Pengrowth generated cash flow from operating activities of $551.3 million for the full year of 2009. Lower commodity prices and lower production in the current year are the major contributors to a 40 percent decrease in operating cash flow and a 27 percent decrease in the operating netback comparing 2009 to 2008. Fourth quarter cash flow from operating activities was $149.9 million, an eight percent decrease from the third quarter of 2009 and three percent decrease from the fourth quarter of 2008. Contributing to the decrease were lower production volumes and unfavorable changes in non-cash operating working capital.

Lower commodity prices in the current year have necessitated a lower level of capital spending when comparing the fourth quarter and the full year of 2009 to the same periods of 2008. Pengrowth has spent approximately 48 percent less capital in the current year compared to 2008, as a response to the lower commodity prices. To the extent possible, capital spending was allocated to those projects that created the greatest economic value.

In the fourth quarter of 2009, Pengrowth recorded net income of $50.5 million compared to $78.3 million and $148.7 million in the third quarter of 2009 and fourth quarter of 2008, respectively. Included in net income are unrealized losses on mark-to-market commodity risk management contracts which result from the change in fair value of the contracts between periods. In the fourth quarter of 2009, an unrealized loss on commodity risk management contracts of $40.1 million before taxes ($29.2 million after tax) was recorded compared to an unrealized loss of $5.6 million before tax ($4.0 million after tax) in the third quarter of 2009 and an unrealized gain of $292.2 million before tax ($207.2 million after tax) in the fourth quarter of 2008. While the strengthening of the Canadian dollar relative to the U.S. dollar during the current quarter had a negative impact on cash flow as lower revenue was received, the stronger dollar resulted in unrealized foreign exchange gains on foreign denominated debt of $17.7 million before tax ($15.4 million after tax) in the fourth quarter of 2009 compared to a gain of $90.0 million before tax ($78.5 million after tax) in the third quarter of 2009 and a loss of $127.2 million before tax ($117.4 million after tax) for the fourth quarter of 2008. For the full year of 2009, net income was approximately $84.9 million; a decrease of 79 percent compared to 2008. This decrease is primarily due to lower price driven revenue, and increased unrealized commodity risk management losses in the current year, partly offset by higher unrealized foreign exchange gains.

The commodity risk management activities, which are utilized to provide a level of stability to the Trust s cash flow from operating activities, has from time to time resulted in the Trust realizing higher commodity prices than those prevailing in the market. Realized commodity risk management gains totalled $27.9 million in the fourth quarter and $171.1 million for the full year 2009. These gains have offset a portion of the Trust s exposure to reduced commodity prices, particularly natural gas.

RESULTS OF OPERATIONS

This MD&A contains the results of Pengrowth Energy Trust and its subsidiaries.

Production

Average daily production decreased approximately one percent in the fourth quarter of 2009 compared to the third quarter of 2009. Fourth quarter production volumes were impacted by cold weather related operational issues and property divestments that were offset by the return to operations of Sable Offshore Energy Project (SOEP) after lengthy third quarter maintenance downtime. In comparison to the fourth quarter of 2008, average daily production decreased seven percent mainly as a result of lower capital reinvestment, natural decline operational issues at SOEP, and property dispositions. Daily production for 2009 decreased three percent compared to 2008 mainly due to the previously mentioned operational issues at SOEP, weather related issues experienced early in 2009 and natural decline, partly offset by additional volumes from capital development, minor property acquisitions in the first quarter and prior period volume additions booked in 2009 that related to prior year acquisitions.

At this time, Pengrowth s 2010 capital program is forecast to deliver average daily production volumes between 74,000 and 76,000 boe per day and remain balanced at approximately 50 percent natural gas and 50 percent crude oil and liquids. This estimate excludes the impact from any potential future acquisitions and dispositions. The 2010 capital spending is anticipated to be $285 million before drilling credits and is designed to replace a portion of production while retaining cash flow for production additions through acquisitions.

Daily Production

	Three months ended						Twelve months ended			
	Dec 31, 2009	**% of total**	Sept 30, 2009	% of total	Dec 31, 2008	% of total	**Dec 31, 2009**	**% of total**	Dec 31, 2008	% of total
Light crude oil (bbls)	**21,948**	**28**	22,930	29	24,236	29	**22,841**	**29**	24,416	30
Heavy oil (bbls)	**7,235**	**9**	7,480	10	8,217	10	**7,551**	**9**	8,122	10
Natural gas (mcf)	**232,682**	**50**	232,444	50	241,709	48	**237,217**	**50**	240,825	49
Natural gas liquids (bbls)	**9,564**	**13**	8,984	11	10,634	13	**9,590**	**12**	9,315	11
Total boe per day	**77,529**		78,135		83,373		**79,518**		81,991	

Light crude oil production volumes decreased approximately four percent in the fourth quarter of 2009 compared to the third quarter of 2009 due to cold weather related operational issues at several western Canadian properties, property dispositions and natural declines. Production volumes decreased approximately nine percent comparing the fourth quarter of 2009 to the fourth quarter of 2008 and approximately seven percent for the full year of 2009 compared to the same time period of 2008. Fourth quarter decreases are the result of lower capital spending in 2009 and natural decline from new well production in the fourth quarter of 2008. The year to date decreases are primarily attributable to weather related operational issues in the fourth quarter, second quarter turnaround work at Nipisi, first quarter operational issues at Judy Creek and natural declines which were partially offset by ongoing development work at Carson Creek.

Heavy oil production decreased approximately three percent compared to the third quarter of 2009. The decrease in the fourth quarter was primarily due to lower than expected performance from recompletions at Cactus Lake and natural decline. The decreases in production comparing the fourth quarter of 2009 and the full year of 2009 to the same periods of 2008 were approximately twelve percent and seven percent, respectively. The decreases are primarily attributable to maintenance activities at Tangleflags and Jenner, and natural declines partially offset by strong performance from the East Bodo polymer flood pilot and well optimizations completed in Plover Lake.

Natural gas production was essentially unchanged in the fourth quarter compared to the third quarter of 2009. Volume increases in the fourth quarter are attributable to the return of SOEP production after the third quarter maintenance shutdown and successes from the Carson Creek development program. Offsetting the volume increases were cold weather related operational issues, lower sales at Judy Creek due to higher volumes being used for miscible flood demand, property dispositions completed late in the fourth quarter and natural decline. Production volumes decreased approximately four percent comparing the fourth quarter of 2009 to the same period of 2008 and approximately two percent on a year-over-year basis. These decreases are a result of planned and unplanned maintenance shutdowns at SOEP and property dispositions partly offset by prior period volume corrections, additional volumes from the gas development program at Carson Creek, and volumes from acquisitions late in 2008 and early in 2009.

NGL production increased approximately seven percent in the fourth quarter of 2009 compared to the third quarter of 2009 primarily due to additional volumes from the development program at Carson Creek. Fourth quarter 2009 production decreased approximately ten percent compared to fourth quarter 2008 and increased three percent on the full year-over-year basis. These decreases are attributable to four condensate lifts at SOEP in 2009 (one in the fourth quarter) compared to six lifts in 2008 (two in the fourth quarter), lower sales volumes from Judy Creek due to higher miscible flood demand in the fourth quarter of 2009 and natural decline, partially offset by the development of new wells at Carson Creek and prior period ethane recoveries at Harmattan.

Table of Contents

Capital Expenditures

($ millions)	Three months ended **Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	Twelve months ended **Dec 31, 2009**	Dec 31, 2008
Drilling, completions and facilities	**40.2**	30.8	82.6	**146.2**	276.5
Drilling Royalty Credits	**(5.1)**	(4.2)		**(9.3)**	
Net drilling, completions and facilities	**35.1**	26.6	82.6	**136.9**	276.5
Seismic acquisitions[1]	**0.2**		0.5	**4.5**	7.6
Maintenance capital	**8.8**	13.3	26.2	**48.5**	57.5
Land purchases[2]	**0.5**	0.2	2.3	**2.9**	26.7
Net development capital	**44.6**	40.1	111.6	**192.8**	368.3
Lindbergh Project	**0.3**	1.8	10.4	**9.4**	20.0
Development capital	**44.9**	41.9	122.0	**202.2**	388.3
Other capital	**1.3**	2.1	3.8	**5.2**	13.6
Total net capital expenditures	**46.2**	44.0	125.8	**207.4**	**401.9**
Business acquisitions			0.2		90.4
Property acquisitions	**25.3**	(0.1)	0.2	**35.7**	35.9
Proceeds on property dispositions	**(34.2)**	0.4	(20.4)	**(41.9)**	(17.4)
Net capital expenditures and acquisitions	**37.3**	44.3	105.8	**201.2**	510.8

[1] Seismic acquisitions are net of seismic sales revenue.

[2] Prior period restated to conform to presentation in the current period.

For the full year of 2009, Pengrowth spent $202.2 million on development and optimization activities net of Drilling Royalty Credits (DRC) of $9.3 million.

The following table shows net development capital expenditures by property classification for the year ended December 31, 2009.

($ millions)	Drilling, Completions, Facilities	Drilling Credits	Maintenance	Seismic Acquisitions	Total
Conventional Gas Properties	56.2	(6.6)	8.9	2.3	60.8
Light Oil Properties	36.5	(0.7)	26.2	2.0	64.0
Shallow/Unconventional Gas	29.6	(1.5)	3.6	0.1	31.8
Heavy Oil Properties	14.3	(0.5)	4.0	0.1	17.9

SOEP	9.6		5.8		15.4
Lindbergh					9.4
Land					2.9
Development Capital	146.2	(9.3)	48.5	4.5	202.2

In addition to development activities, $9.4 million was spent on the Lindbergh project and $5.2 million was spent on corporate items.

Pengrowth currently anticipates the 2010 capital program to be $285 million before drilling credits and focuses on balancing opportunities between delivering results from its existing asset base and the acquisition of assets in existing and new core areas. The 2010 capital program is designed to be flexible, scalable and responsive to uncertain commodity prices and market conditions. Capital amounts may fluctuate and may be reallocated between natural gas and oil opportunities in response to fluctuations of commodity prices. Pengrowth will continue to monitor and adjust capital investment ensuring that it optimizes value and continues to live within its cash flow.

Reserves

During 2009, Pengrowth s development and optimization activities resulted in the addition of 11.3 mmboe of Proved Reserves and 2.6 mmboe of Total Proved Plus Probable Reserves including revisions. Negative revisions were made that amounted to 3.3 mmboe in Total Proved and 9.7 mmboe in Total Proved plus Probable reserves, partially offset by positive revisions of 7.5 mmboe in Total Proved and 3.5 mmboe in Total Proved Plus Probable reserves. These relate to reserves attributed to high cost natural gas properties where development of these assets was unlikely given the shifting corporate strategy and the outlook for natural gas prices.

Pengrowth reported year-end proved reserves of 216.6 mmboe and proved plus probable reserves of 295.7 mmboe for 2009 compared to 235.2 mmboe and 323.5 mmboe, respectively at year end 2008. Further details of Pengrowth s 2009 year-end reserves are provided in the AIF which is filed on SEDAR or the 40F filed on Edgar.

Table of Contents

Acquisitions and Dispositions

In the fourth quarter of 2009, Pengrowth completed the acquisitions of an additional interest in the House Mountain unit and in the Horn River basin for approximately $13.5 million and $11.0 million, respectively, net of adjustments. Pengrowth also completed the disposition of non-core properties mainly in the Niton area of Alberta for net proceeds of $33.9 million.

In the first and second quarters of 2009, Pengrowth completed two acquisitions in the Carson Creek area for approximately $8.9 million and $1.8 million net of adjustments, respectively.

During the first quarter of 2009, Pengrowth completed the disposition of non-core properties in the Dawson area in British Columbia. Proceeds of the disposition were approximately $6.4 million net of adjustments.

Pricing and Commodity Risk Management

Pengrowth s commodity price realizations are influenced by the benchmark prices. During 2009 realized gains from commodity risk management activities have partially offset the effects of lower commodity prices, whereas in 2008 realized losses reduced the net realized prices.

As part of its risk management strategy, Pengrowth uses forward price swaps to manage its exposure to commodity price fluctuations to provide a measure of stability to monthly cash flow.

As of December 31, 2009, the following commodity risk management contracts were in place:

Crude Oil:

Remaining term	Volume (bbl/d)	Reference Point	Price per bbl
Financial:			
Jan 1, 2010 - Dec 31, 2010	12,500	WTI (1)	$82.09 Cdn
Jan 1, 2011 - Dec 31, 2011	500	WTI (1)	$82.44 Cdn

(1) Associated Cdn $/U.S. $ foreign exchange rate has been fixed

Natural Gas:

Remaining term	Volume (mmbtu/d)	Reference Point	Price per mmbtu
Financial:			
Jan 1, 2010 - Dec 31, 2010	97,151	AECO	$6.10 Cdn
Jan 1, 2010 - Dec 31, 2010	5,000	Chicago MI (1)	$6.78 Cdn
Jan 1, 2011 - Dec 31, 2011	33,174	AECO	$5.77 Cdn
Jan 1, 2011 - Dec 31, 2011	5,000	Chicago MI (1)	$6.78 Cdn

(1) Associated Cdn $/U.S. $ foreign exchange rate has been fixed

Power:

Remaining term	Volume (mwh)	Reference Point	Price per mwh
Financial:			
Jan 1, 2010 - Dec 31, 2010	20	AESO	$47.66 Cdn

Based on our preliminary 2010 production estimates, the above contracts represent approximately 34 percent of total liquids volumes at average realizations of $82.09 per bbl (2009 43 percent of full year volumes at $86.34 per bbl) and 45 percent of natural gas volumes at $6.13 per mmbtu (2009 32 percent of full year volumes at $8.00 per mmbtu). The power contract represents approximately 20 percent of our estimated 2010 consumption.
Each Cdn $1 per barrel change in future oil prices would result in approximately Cdn $4.7 million pre-tax change in the value of the crude contracts. Similarly, each Cdn $0.25 per mcf change in future natural gas prices would result in approximately Cdn $12.8 million pre-tax change in the value of the natural gas contracts. Similarly, each Cdn $1 per MWh change in future power prices would result in approximately Cdn $0.2 million pre-tax change in the unrealized gain (loss) on commodity risk management contracts. The changes in the fair value of the forward contracts directly affects reported net income through the unrealized

amounts recorded in the statement of income during the period. The effect on cash flow will be recognized separately only upon realization of the contracts, which could vary significantly from the unrealized amount recorded due to timing and prices when each contract is settled. However, if each contract were to settle at the contract price in effect at December 31, 2009, future revenue and cash flow would decrease by $9.0 million based on the estimated fair value of the risk management liability at year end. The $9.0 million net liability is composed of a net liability of $2.7 million relating to contracts expiring in 2010 and a liability of $6.3 million relating to contracts expiring in 2011. Pengrowth has fixed the Canadian dollar exchange rate at the same time that it swaps any U.S. dollar denominated commodity in order to protect against changes in the foreign exchange rate.

Pengrowth has not designated any outstanding commodity contracts as hedges for accounting purposes and therefore records these contracts on the balance sheet at their fair value and recognizes changes in fair value in the income statement as unrealized commodity risk management gains or losses. There will continue to be volatility in earnings to the extent that the fair value of commodity contracts fluctuate however, these non-cash amounts do not impact Pengrowth s operating cash flow. Realized commodity risk management gains or losses are recorded in oil and gas sales on the income statement and impacts cash flow at that time.

Average Realized Prices

	Three months ended			Twelve months ended	
(Cdn$)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Light crude oil (per bbl)	**74.37**	69.28	60.76	**63.94**	98.20
after realized commodity risk management	**75.79**	74.40	65.87	**72.36**	77.78
Heavy oil (per bbl)	**62.16**	59.21	42.20	**52.72**	75.77
Natural gas (per mcf)	**4.28**	2.82	6.97	**3.97**	8.32
after realized commodity risk management	**5.45**	4.34	7.40	**5.14**	8.19
Natural gas liquids (per bbl)	**54.52**	41.86	43.87	**42.12**	70.67
Total per boe	**46.44**	39.18	47.60	**40.29**	69.24
after realized commodity risk management	**50.35**	45.22	50.34	**46.19**	62.76
Other production income	**0.02**	0.03	0.78	**0.08**	1.19
Total oil and gas sales per boe	**50.37**	45.25	51.12	**46.27**	63.95
Benchmark prices					
WTI oil (U.S.$ per bbl)	**76.19**	68.30	58.73	**61.80**	99.65
AECO spot gas (Cdn$ per mmbtu)	**4.23**	3.03	6.78	**4.14**	8.12
NYMEX gas (U.S.$ per mmbtu)	**4.17**	3.39	6.94	**3.99**	9.04
Currency (U.S.$/Cdn$)	**0.95**	0.91	0.83	**0.88**	0.94

Lower commodity prices during the full year of 2009 compared to the same period of 2008 had the most significant impact on earnings and operating cash flow.

Commodity Risk Management Gains (Losses)

	Three months ended	Twelve months ended
Realized		

	Dec 31, 2009	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Light crude oil ($ millions)	**2.9**	10.8	11.4	**70.2**	(182.5)
Light crude oil ($ per bbl)	**1.42**	5.12	5.11	**8.42**	(20.42)
Natural gas ($ millions)	**25.0**	32.6	9.6	**101.0**	(11.8)
Natural gas ($ per mcf)	**1.17**	1.52	0.43	**1.17**	(0.13)
Combined ($ millions)	**27.9**	43.4	21.0	**171.1**	(194.3)
Combined ($ per boe)	**3.91**	6.04	2.74	**5.90**	(6.48)
Unrealized					
Total unrealized risk management assets (liabilities) at period end ($ millions)	**(9.0)**	31.1	164.7	**(9.0)**	164.7
Less: Unrealized risk management assets (liabilities) at beginning of period ($ millions)	**31.1**	36.7	(127.6)	**164.7**	(85.2)
Unrealized (loss) gain on risk management contracts	**(40.1)**	(5.6)	292.3	**(173.7)**	249.9

Commodity risk management activities have reduced the volatility in cash flow in 2009 and 2008, with 2009 having a positive impact and 2008 having a negative impact. Approximately 31 percent of cash flow from operations for the year ended December 31, 2009, resulted from realized commodity risk management gains.

Throughout 2009 oil prices increased while natural gas prices declined through the first three quarters, increasing in the fourth quarter. However, both commodity prices remained lower than average prices established in the commodity risk management

Table of Contents

contracts resulting in realized commodity risk management gains. These gains are included in oil and gas sales in the income statement.

As the commodity risk management contracts settle, the effect on cash flow will vary due to timing, prices and the volume under contract. For example, the commodity risk management gains positively impacted cash flow in the fourth quarter of 2009 by $27.9 million, the fourth quarter of 2008 by $21.0 million and the full year of 2009 by $171.1 million, while the full year of 2008 experienced losses of $194.3 million, which negatively impacted cash flow.

Oil and Gas Sales Contribution Analysis

The following table includes revenue from the sale of oil and natural gas and the impact of realized commodity risk management activity.

($ millions)	Three months ended						Twelve months ended			
Sales Revenue	**Dec 31, 2009**	**% of total**	Sept 30, 2009	% of total	Dec 31, 2008	% of total	**Dec 31, 2009**	**% of total**	Dec 31, 2008	% of total
Light crude oil	**153.0**	**43**	157.0	48	146.9	37	**603.2**	**45**	695.1	36
Natural gas	**116.8**	**33**	92.7	28	164.5	42	**444.8**	**33**	722.1	38
Natural gas liquids	**47.9**	**13**	34.6	11	42.9	11	**147.4**	**11**	240.9	12
Heavy oil	**41.4**	**11**	40.7	13	31.9	8	**145.3**	**11**	225.3	12
Brokered sales/sulphur	**0.2**		0.3		5.9	2	**2.5**		35.6	2
Total oil and gas sales	**359.3**		325.3		392.1		**1,343.2**		1,919.0	

Oil and Gas Sales Price and Volume Analysis

The following table illustrates the effect of changes in prices and volumes on the components of oil and gas sales including the impact of realized commodity risk management activity, on a year-over-year basis.

($ millions)	Light oil	Natural gas	NGLs	Heavy oil	Other (1)	Total
Year ended Dec 31, 2008	695.1	722.1	240.9	225.3	35.6	1,919.0
Effect of change in product prices	(285.7)	(377.2)	(99.9)	(63.5)		(826.3)
Effect of change in sales volumes	(58.8)	(13.0)	6.4	(16.5)		(81.9)
Effect of change in realized commodity risk management activities	252.7	112.8				365.5
Other	(0.1)	0.1			(33.1)	(33.1)
Year ended Dec 31, 2009	603.2	444.8	147.4	145.3	2.5	1,343.2

(1) Primarily sulphur sales

Processing and Other Income

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Processing & other income	**2.5**	3.4	2.3	**15.5**	15.5
$ per boe	**0.35**	0.48	0.31	**0.54**	0.52

Processing and other income is primarily derived from fees charged for processing and gathering third party gas, road use, oil and water processing. Income is lower in the fourth quarter 2009 compared to the third quarter of 2009 primarily a result of the timing of booking road use fees.

This income primarily represents the partial recovery of operating expenses reported separately.

Royalty Expense

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Royalty expense	**71.0**	49.7	80.7	**207.6**	434.0
$ per boe	**9.95**	6.91	10.51	**7.15**	14.46
Royalties as a percent of sales	**19.7%**	15.3%	20.6%	**15.5%**	22.6%
Royalties as a percent of sales excluding realized risk management contracts	**21.4%**	17.6%	21.7%	**17.7%**	20.5%

12

Royalties include Crown, freehold and overriding royalties as well as mineral taxes. Royalty payments are based on revenue prior to commodity risk management activities. Gains or losses from realized commodity risk management activities are reported as part of sales and therefore affect royalty rates as a percentage of sales. The increase in the royalty rate in the fourth quarter 2009 compared to the third quarter is a result of higher gas commodity prices excluding the effects of risk management contracts. Offsetting the unfavorable impact of price on royalties was a favorable prior period royalty adjustment of $2.4 million at the Harmattan property. The lower royalty rate in the current period comparing fourth quarter and the full year of 2009 to the same time periods of 2008 is reflective of lower commodity prices and the implementation of The New Royalty Framework in Alberta which became effective January 1, 2009.

Royalty expense for 2010 is forecasted to be approximately 21 percent of Pengrowth s sales excluding the impact of risk management contracts.

Operating Expenses

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Operating expenses	**92.4**	92.8	104.1	**381.2**	418.5
$ per boe	**12.95**	12.91	13.57	**13.13**	13.95

Operating expenses remained relatively unchanged in the fourth quarter of 2009 compared to the third quarter of 2009. Increased subsurface activity at Goose River, Carson Creek and Jenner was offset by decreased utility expenses and prior period accounting adjustments related to overhead recoveries on producing properties. Fourth quarter 2009 operating expenses decreased $11.7 million compared to the fourth quarter of 2008, mainly a result of a 47 percent decrease in power prices, but also due to lower subsurface maintenance and the deferral of planned maintenance projects in the current quarter. Operating expenses for 2009 compared to 2008 decreased by $37.3 million, mainly attributable to a 42 percent decrease in power prices. Also contributing to the reduction in operating costs was the absence of turnaround expenses at Olds, reduced surface and subsurface maintenance activities due to the deferral of projects in the current period and prior period accounting adjustments related to overhead recoveries, partly offset by maintenance expenses related to a SOEP turnaround.

Operating costs are anticipated to be $395 million for the full year of 2010; however per boe operating costs are estimated to increase to $14.40 per boe. The expected increase in per boe operating costs is primarily attributed to lower production in 2010.

Net Operating Expenses

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Net operating expenses	**89.9**	89.4	101.8	**365.7**	403.0
$ per boe	**12.59**	12.43	13.27	**12.59**	13.43

Included in the table above are operating expenses net of processing and other income.

Transportation Costs

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008

Light oil transportation	**1.2**	1.6	0.4	**4.7**	3.4
$ per bbl	**0.58**	0.78	0.19	**0.56**	0.38
Natural gas transportation	**2.9**	2.2	2.3	**8.8**	9.1
$ per mcf	**0.14**	0.10	0.10	**0.10**	0.10

Pengrowth incurs transportation costs for its natural gas production once the product enters a pipeline at a title transfer point. Pengrowth also incurs transportation costs on its oil production that includes clean oil trucking charges and pipeline costs once the product enters a feeder or main pipeline. The increase in light oil transportation in the third and fourth quarters of 2009 and for the full year of 2009 compared to 2008 is related to higher clean oil trucking costs. The transportation cost is dependent upon third party rates and distance the product travels on the pipeline prior to changing ownership or custody. Pengrowth has the option to sell some of its natural gas directly to markets outside of Alberta by incurring additional transportation costs. Pengrowth

Table of Contents

sells most of its natural gas without incurring significant additional transportation costs. Similarly, Pengrowth has elected to sell approximately 80 percent of its crude oil at market points beyond the wellhead but at the first major trading point, requiring minimal transportation costs.

Amortization of Injectants for Miscible Floods

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Purchased and capitalized	**4.9**	1.7	5.4	**13.3**	21.0
Amortization	**4.4**	4.8	5.9	**20.0**	25.9

The cost of injectants (primarily natural gas and ethane) purchased for injection in the miscible flood program at Judy Creek and Swan Hills is amortized equally over the period of expected future economic benefit. The costs of injectants purchased are amortized over a 24 month period. As of December 31, 2009, the balance of unamortized injectant costs was $15.7 million.

The amount of injectants purchased and capitalized in the fourth quarter 2009 was higher than the third quarter of 2009. The value of Pengrowth s proprietary injectants is not recorded as an asset or a sale; the cost of producing these injectants is included in operating expenses. The total volume injected and the cost of the injectants was lower in 2009 compared to 2008.

Operating Netbacks

There is no standardized measure of operating netbacks and therefore operating netbacks, as presented below, may not be comparable to similar measures presented by other companies. Pengrowth s operating netbacks have been calculated by taking GAAP balances directly from the income statement and dividing by production. Certain assumptions have been made in allocating operating expenses, processing and other income and royalty injection credits between light crude, heavy oil, natural gas and NGL production.

Pengrowth recorded an average operating netback of $26.63 per boe in the fourth quarter of 2009 compared to $24.72 per boe in the third quarter of 2009 and $26.23 per boe for the fourth quarter of 2008. The increase in the netback in the fourth quarter of 2009 compared to the third quarter of 2009 is primarily attributable to higher combined commodity prices. The decrease in operating netback comparing the full year of 2009 with the full year of 2008 was primarily a result of lower combined commodity price realizations partly offset by lower royalty expenses and operating costs.

The sales price used in the calculation of operating netbacks is after realized commodity risk management gains or losses.

Table of Contents

Combined Netbacks ($ per boe)	Three months ended Dec 31, 2009	Sept 30, 2009	Dec 31, 2008	Twelve months ended Dec 31, 2009	Dec 31, 2008
Oil & gas sales	**50.37**	45.25	51.12	**46.27**	63.95
Processing and other income	**0.35**	0.48	0.31	**0.54**	0.52
Royalties	**(9.95)**	(6.91)	(10.51)	**(7.15)**	(14.46)
Operating expenses	**(12.95)**	(12.91)	(13.57)	**(13.13)**	(13.95)
Transportation costs	**(0.57)**	(0.52)	(0.35)	**(0.46)**	(0.42)
Amortization of injectants	**(0.62)**	(0.67)	(0.77)	**(0.69)**	(0.86)
Operating netback	**26.63**	24.72	26.23	**25.38**	34.78

Light Crude Netbacks ($ per bbl)	Three months ended Dec 31, 2009	Sept 30, 2009	Dec 31, 2008	Twelve months ended Dec 31, 2009	Dec 31, 2008
Sales price (after commodity risk management)	**75.79**	74.40	65.87	**72.36**	77.78
Other production income	**0.23**	0.43	(0.02)	**0.32**	0.19
Oil & gas sales	**76.02**	74.83	65.85	**72.68**	77.97
Processing and other income	**0.46**	0.34	0.06	**0.71**	0.62
Royalties(1)	**(17.35)**	(15.94)	(14.02)	**(13.65)**	(16.73)
Operating expenses(2)	**(17.36)**	(15.76)	(21.47)	**(16.28)**	(17.03)
Transportation costs	**(0.58)**	(0.78)	(0.19)	**(0.56)**	(0.38)
Amortization of injectants	**(2.19)**	(2.29)	(2.64)	**(2.40)**	(2.90)
Operating netback	**39.00**	40.40	27.59	**40.50**	41.55

Heavy Oil Netbacks ($ per bbl)	Three months ended Dec 31, 2009	Sept 30, 2009	Dec 31, 2008	Twelve months ended Dec 31, 2009	Dec 31, 2008
Oil & gas sales	**62.16**	59.21	42.20	**52.72**	75.77
Processing and other income	**(0.84)**	1.05	0.29	**0.53**	0.32
Royalties(1) (3)	**(12.81)**	(6.74)	(1.95)	**(8.91)**	(10.54)
Operating expenses(1) (2)	**(12.31)**	(14.18)	(18.85)	**(14.35)**	(14.02)
Operating netback	**36.20**	39.34	21.69	**29.99**	51.53

Natural Gas Netbacks ($ per mcf)	Three months ended Dec 31, 2009	Sept 30, 2009	Dec 31, 2008	Twelve months ended Dec 31, 2009	Dec 31, 2008

Sales price (after commodity risk management)	**5.45**	4.34	7.40	**5.14**	8.19
Other production income	**(0.01)**	(0.03)	0.27		0.39
Oil & gas sales	**5.44**	4.31	7.67	**5.14**	8.58
Processing and other income	**0.10**	0.09	0.09	**0.09**	0.10
Royalties(1) (4)	**(0.58)**	(0.12)	(1.62)	**(0.31)**	(1.88)
Operating expenses(2)	**(1.83)**	(1.87)	(1.37)	**(1.89)**	(2.02)
Transportation costs	**(0.14)**	(0.10)	(0.10)	**(0.10)**	(0.10)
Operating netback	**2.99**	2.31	4.67	**2.93**	4.68

	Three months ended			**Twelve months ended**	
NGLs Netbacks ($ per bbl)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Oil & gas sales	**54.52**	41.87	43.87	**42.12**	70.67
Royalties(1)	**(17.06)**	(10.70)	(12.27)	**(12.08)**	(25.74)
Operating expenses(2)	**(11.34)**	(11.91)	(11.71)	**(11.99)**	(13.58)
Operating netback	**26.12**	19.26	19.89	**18.05**	31.35

(1) Royalty expense in 2009 are lower compared to 2008, a result of lower commodity prices and the implementation of The Alberta Royalty Framework on January 1, 2009.

(2) Prior period restated to conform to presentation in the current period.

(3) Heavy oil royalties in the fourth quarter includes an unfavorable crown royalty adjustment at

Tangleflags.

(4) Gas royalties in the fourth quarter increased due to volumes at SOEP being back on production which has a higher associated royalty rate.

Interest Expense

($ millions)	Three months ended **Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	Twelve months ended **Dec 31, 2009**	Dec 31, 2008
Interest Expense	**18.3**	19.4	22.6	**80.3**	76.3

At December 31, 2009, Pengrowth had $1,151.5 million of debt outstanding composed of $907.6 million in long term debt, $74.8 million in convertible debentures, $157.5 million in current portion of long term debt and $11.6 million of bank indebtedness. Of this, approximately 94 percent is fixed at a weighted average interest rate of 6.2 percent, with the remaining 6 percent subject to floating rates. As part of Pengrowth s overall risk management strategy, the majority of the fixed rate debt is denominated in U.S. dollars and incurs interest in U.S. dollars and is therefore subject to fluctuations in the U.S. dollar exchange rates.

Table of Contents

General and Administrative Expenses

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Cash G&A expense	**14.7**	11.2	13.7	**54.1**	48.9
$ per boe	**2.06**	1.56	1.79	**1.86**	1.63
Non-cash G&A expense	**(0.6)**	2.5	3.5	**8.1**	10.0
$ per boe	**(0.08)**	0.35	0.45	**0.28**	0.33
Total G&A	**14.1**	13.7	17.2	**62.2**	58.9
$ per boe	**1.98**	1.91	2.24	**2.14**	1.96

The cash component of general and administrative (G&A) expenses increased $3.5 million in the fourth quarter of 2009 compared to the third quarter of 2009. This increase is primarily due to higher tax consulting fees related to preparation of final partnership returns for U.S. investors, final reimbursement of expenses incurred by the Manager pursuant to the expired management agreement, and fees related to the annual reserve evaluation. For the full year of 2009, cash G&A increased $5.2 million compared to 2008. This increase is primarily due to reimbursement of expenses incurred by the Manager, additional expenses related to corporate development activities and additional fees for tax consulting incurred in the current year.

The non-cash component of G&A represents the compensation expense associated with Pengrowth s Long Term Incentive Programs (LTIP) including trust unit rights and deferred entitlement units (DEU). These compensation programs are expensed over the applicable vesting period of two or three years. The decrease comparing the full year of 2009 to 2008 is primarily due to applying a lower performance multiplier to the 2007 DEU grant based on actual performance.

The G&A expenses are expected to be flat or slightly lower in 2010 compared to 2009. On a per boe basis, G&A expenses are anticipated to be $2.23 per boe for the full year 2010. This estimate includes costs expected to be incurred in 2010 associated with Pengrowth s anticipated conversion from a trust to a dividend paying corporation on or before January 1, 2011.

Management Fees

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Management Fee			(2.0)	**2.8**	7.0
$ per boe			(0.26)	**0.10**	0.23

The management agreement expired on June 30, 2009.

Management fees were $2.8 million for the full year of 2009 or $0.10 per boe.

Related Party Transactions

The management agreement with Pengrowth Management Limited (the Manager) expired on June 30, 2009. The Manager provided certain services pursuant to the management agreement. In 2009 Pengrowth was charged $2.8 million for management fees (2008 $6.9 million). In addition, Pengrowth was charged $2.1 million (2008 $1.1 million) for reimbursement of general and administrative expenses incurred by the Manager. Amounts charged by the Manager were pursuant to a management agreement approved by the unitholders. The law firm controlled by

the former Corporate Secretary of the Corporation charged $0.8 million in 2009 (2008 $1.0 million) for legal and advisory services provided to Pengrowth. The fees charged by this law firm have been recorded at the exchange amount which management believes approximates the fair value. Amounts receivable or payable from or to the related parties are unsecured, non-interest bearing and have no set terms of repayment. During 2009, the former Corporate Secretary was granted 44,304 trust unit rights and 8,861 DEUs (2008 23,670 trust unit rights and 3,945 DEUs).
A senior officer of the Corporation is a member of the Board of Directors of Monterey, a company that Pengrowth owns approximately 20 percent of the outstanding common shares.

Other Expenses

Included in other expenses for the full year of 2009 is $2.9 million for a settlement with the former CEO and $3.7 million to reflect Pengrowth s proportionate share of Monterey Exploration Ltd. s (Monterey) net loss (2008 $1.4 million pre-tax income), a company which Pengrowth owns approximately 20 percent of the outstanding common shares (2008 24 percent).
On February 19, 2010, Monterey issued additional equity in a public offering, in which Pengrowth purchased 952,500 shares of Monterey for approximately $4.0 million. Pengrowth continues to own approximately 20 percent of the outstanding common shares after this purchase.

Taxes

In determining its taxable income, the Corporation deducts payments made to the Trust, effectively transferring the income tax liability to unitholders thus reducing the Corporation s taxable income to nil. Under the Corporation s current distribution policy, at the discretion of the board, funds can be withheld to fund future capital expenditures, repay debt or used for other corporate purposes. If withholdings increased sufficiently or the Corporation s tax pool balances were reduced sufficiently, the Corporation could become subject to taxation on a portion of its income in the future. This can be mitigated through various options including the issuance of additional trust units, increased tax pools from additional capital spending, modifications to the distribution policy or potential changes to the corporate structure.

Bill C-52 Budget Implementation Act 2007

Bill C-52 modifies the taxation of certain flow-through entities including mutual fund trusts referred to as specified investment flow-through entities or SIFTS and the taxation of distributions from such entities (the SIFT Legislation). Bill C-52 applies a tax at the trust level on distributions of certain income from such a SIFT trust at a rate of tax comparable to the combined federal and provincial corporate tax rate (the SIFT tax). These distributions will be treated as dividends to the trust unitholders.

Pengrowth believes that it is characterized as a SIFT trust and, as a result, will be subject to Bill C-52 commencing on January 1, 2011 subject to the qualification below regarding the possible loss of the four year grandfathering period in the case of undue expansion . Pengrowth may lose the benefit of the grandfathering period, which ends December 31, 2010, if Pengrowth exceeds the limits on the issuance of new trust units and convertible debt that constitute normal growth during the grandfathering period (subject to certain exceptions). The normal growth limits are calculated as a percentage of Pengrowth s market capitalization of approximately $4.8 billion on October 31, 2006. The normal growth guidelines have been revised to accelerate the safe harbour amount for 2010. As of December 31, 2009 Pengrowth may issue an additional $3.9 billion of equity in total for 2010 under the safe harbour provisions. The normal growth restriction on trust unit issuance is monitored by management as part of the overall capital management objectives. Pengrowth is in compliance with the normal growth restrictions.

Based on existing tax legislation, the SIFT tax rate in 2011 is expected to be 26.5 percent and 25 percent in 2012 and subsequent years. The payment of this tax would reduce the amount of cash available for distribution to unitholders.

On July 14, 2008, Finance released for comment proposed amendments to the *Income Tax Act* (Canada) to facilitate the conversion of existing income trusts and other public flow through entities into corporations on a tax deferred basis. Bill C-10, which received Royal Assent on March 12, 2009, contained legislation implementing the conversion rules. The conversion rules would provide an existing income trust with tax efficient structuring options to convert to a corporate form. The transition provisions are only available to trusts that convert prior to 2013. Pengrowth can continue to have the benefit of its tax structure through December 31, 2010.

Pengrowth currently anticipates converting to a dividend paying corporation on or before January 1, 2011. Pengrowth has available tax pool balances of approximately $2.9 billion at December 31, 2009, which will be used to reduce any corporate cash taxes otherwise payable.

Future Income Taxes

Future income tax is a non-cash item relating to temporary differences between the accounting and tax basis of Pengrowth s assets and liabilities and has no immediate impact on Pengrowth s cash flows. During the year-ended December 31, 2009, Pengrowth recorded a future tax reduction of $143 million. The future income tax reduction includes approximately $99 million related to the taxable income at the trust level where both the income tax and future tax liabilities are currently the responsibility of the unitholder. The current year reduction is also attributable to temporary differences relating to unrealized risk management losses as well as non-taxable unrealized foreign exchange gains. See Note 11 for additional information.

Table of Contents

Foreign Currency Gains & Losses

Pengrowth recorded a $149.7 million net foreign exchange gain in 2009, compared to a $189.2 million net foreign exchange loss in 2008. Included in the gain is a $144.5 million unrealized foreign exchange gain related to the translation of the U.S. dollar denominated debt and a $3.8 million unrealized foreign exchange gain for the U.K. Pound Sterling denominated debt using the closing exchange rate at the end of each year. Pengrowth has mitigated the foreign exchange risk on the interest and principal payments related to the U.K. Pound Sterling denominated notes (see Note 9 to the financial statements) by using foreign exchange swaps.

Revenues are recorded at the average exchange rate for the production month in which they accrue, with payment being received on or about the 25th of the following month. As a result of the changes in the Canadian dollar relative to the U.S. dollar over the course of the year, a foreign exchange gain was recorded to the extent that there was a difference between the average exchange rate for the month of production and the exchange rate at the date the payments were received on that portion of production sales that are received in U.S. dollars.

As some realized commodity prices are derived from U.S. denominate benchmarks a weaker U.S. dollar negatively impacts oil and gas revenues. To mitigate this Pengrowth elects to hold a portion of its long term debt in U.S. dollars as a natural hedge. Therefore a decline in revenues as a result of foreign exchange fluctuations will be partially offset by a reduction in U.S. dollar interest expense. (See Note 15 to the financial statements.)

Depletion, Depreciation and Accretion

	Three months ended			Twelve months ended	
($ millions)	**Dec 31, 2009**	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Depletion and depreciation	**144.3**	147.2	157.6	**591.4**	609.3
$ per boe	**20.23**	20.48	20.55	**20.38**	20.31
Accretion	**7.1**	7.0	7.3	**27.7**	28.1
$ per boe	**1.00**	0.97	0.95	**0.95**	0.93

Depletion and depreciation of property, plant and equipment is calculated using the unit of production method based on total proved reserves. The decrease in the depletion amount is due to lower production volumes realized in the current quarter.

Pengrowth s Asset Retirement Obligations (ARO) liability is increased for the passage of time (unwinding of the discount) through a charge to earnings that is referred to as accretion. Accretion is charged to net income over the lifetime of the producing oil and gas assets.

Ceiling Test

Under Canadian GAAP, a ceiling test is applied to the carrying value of the property, plant and equipment and other assets. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flow expected from the production of proved reserves, the lower of cost and market of unproved properties, and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flow expected from the production of proved and probable reserves, the lower of cost and market of unproved properties, and the cost of major development projects. The cash flow is estimated using expected future product prices and costs and are discounted using a risk-free interest rate, when required. There was a significant surplus in the Canadian GAAP ceiling test at December 31, 2009 and 2008.

As required annually under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of future or deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves (discounted at ten percent), plus the lower of cost and fair value of unproven properties. The 2009 year end U.S. GAAP ceiling test was based on new rules requiring the after tax future net revenue from proven reserves to be determined using the average commodity price on the first day of each month in 2009. At December 31, 2009, the U.S. GAAP ceiling test did not result in a write-down of capitalized costs. In the prior year, the commodity prices used to determine the after tax future net revenue was based on the price in effect on the date of the ceiling test.

Asset Retirement Obligations

The total future ARO is based on management s estimate of costs to remediate, reclaim and abandon wells and facilities having regard for Pengrowth s working interest and the estimated timing of the costs to be incurred in future periods. Pengrowth has developed an internal process to calculate these estimates which considers applicable regulations, actual and anticipated costs, type and size of well or facility and the geographic location. Pengrowth has estimated the net present value of its total ARO to be $289 million as at December 31, 2009 (December 31, 2008 $344 million), based on a total escalated future liability of $2.0 billion (December 31, 2008 $2.3 billion). These costs are expected to be incurred over 50 years with the majority of the costs incurred between 2039 and 2056. A credit adjusted risk free rate of eight percent and an inflation rate of two percent per annum were used to calculate the net present value of the ARO in 2009 and 2008.

For the year ended December 31, 2009, Pengrowth s ARO liability decreased $55 million which included a $66.5 million downward revision to the ARO liability (see Note 10 to the audited financial statements for details). The revision was as a result of management s re-evaluation of cost estimates used to determine the ARO liability and timing of future abandonment, reclamation, and remediation work. This revision was consistent with experience on actual ARO costs achieved in 2009 and a study on economies of scale by an independent environmental consulting firm on large scale remediation and reclamation projects. This information indicated that the cost estimates used in determining the ARO were higher than what were achieved through economies of scale in 2009 and were adjusted based on the information obtained. The timing of future abandonment, reclamation and remediation work was also revised to coincide with the assumption that when possible, Pengrowth would perform large scale ARO projects over specific areas rather than on well by well basis. This resulted in the deferral of several ARO projects into the future as well as cost efficiencies through scale. Management believes that the revisions made to cost estimates and to the timing of certain future ARO projects are more reflective of the company s strategic approach to managing its abandonment, reclamation and remediation activities. Management reviews the ARO estimate and changes, if any, are applied prospectively. Revisions made to the ARO estimate are recorded as an increase or decrease to the ARO liability with a corresponding entry made to the carrying amount of the related asset.

Remediation Trust Funds and Remediation and Abandonment Expense

During 2009, Pengrowth contributed $8.3 million into trust funds established to fund certain abandonment and reclamation costs associated with Judy Creek and SOEP. The balance in these remediation trust funds was $34.8 million at December 31, 2009.

Every five years Pengrowth must evaluate the value of the assets in the Judy Creek remediation trust fund and the outstanding ARO, and make recommendations to the former owner of the Judy Creek properties as to whether contribution levels should be changed. The next evaluation is anticipated to occur in 2012. Contributions to the Judy Creek remediation trust fund may change based on future evaluations of the fund.

As a working interest holder in SOEP, Pengrowth is under a contractual obligation to contribute to a remediation trust fund. The funding levels are based on the feedstock handled and delivered to the various facilities; funding levels for this fund may change each year pending a review by the owners.

Pengrowth takes a proactive approach to managing its well abandonment and site restoration obligations. There is an on-going program to abandon wells and reclaim well and facility sites. During 2009, Pengrowth spent $18.0 million on abandonment and reclamation (December 31, 2008 - $32.7 million). Pengrowth expects to spend approximately $20.0 million in 2010 on reclamation and abandonment, excluding contributions to remediation trust funds and orphan well levies from the Alberta Energy Resources Conservation Board.

Climate Change Programs

In Alberta, climate change regulations became effective July 1, 2007. These regulations require Alberta facilities that emit more than 100,000 tonnes of greenhouse gases a year to reduce emissions intensity by 12 percent over the average emission levels of 2003, 2004 and 2005. Companies can make their reductions through improvements to their operations; by purchasing Alberta-based offset credits or by contributing to the Climate Change and Emissions Management Fund. Pengrowth currently operates two facilities that are subject to the Alberta climate change regulations. Collectively these facilities have reduced emissions by 17 percent from the base line emissions (2008 data). This reduction is an improvement over current-day requirements. Pengrowth is assessing options for meeting future greenhouse gas emission requirements. However, if the emissions remain at the current levels, Pengrowth would experience additional annual costs of as much as $0.5 million for the acquisition of credits relating to one facility. For further information, see Pengrowth s AIF. Pengrowth is waiting on additional information from other jurisdictions to assess the impact it will have on its operations.

Goodwill

As at December 31, 2009, Pengrowth recorded goodwill of $660.9 million.

In accordance with GAAP, the goodwill balance must be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such impairment exists, it would be charged to income in the period in which the impairment occurs. Management has assessed goodwill for impairment and determined there is no impairment at December 31, 2009.

Working Capital

The working capital deficiency increased at December 31, 2009 by $146.8 million compared to December 31, 2008. The change in working capital is primarily attributable to $157.5 million of long term debt reclassified to a current liability as it is now due to be repaid in April 2010 and the change in the fair value of commodity risk management contracts, partly offset by lower accounts payable and distributions payable.

Pengrowth generally operates with a working capital deficiency, as the production revenue relating to one month of distributions payable to unitholders is used for general corporate purposes and to reduce long term debt.

Table of Contents

Financial Resources and Liquidity

Pengrowth s capital structure is as follows:

($ thousands) As at:	Dec 31, 2009	Dec 31, 2008	Change
Term credit facilities	$ 60,000	$ 372,000	$(312,000)
Senior unsecured notes[(1)]	847,599	1,152,503	(304,904)
Total long term debt	907,599	1,524,503	(616,904)
Working capital deficit	59,461	70,159	(10,698)
Current portion of long term debt	157,546		157,546
Working capital deficiency	217,007	70,159	146,848
Total debt excluding convertible debentures	$1,124,606	$1,594,662	$(470,056)
Convertible debentures	74,828	74,915	(87)
Total debt including convertible debentures	$1,199,434	$1,669,577	$(470,143)

Years ended	Dec 31, 2009	Dec 31, 2008	Change
Net income	$ 84,853	$ 395,850	$(310,997)
Add:			
Interest expense	$ 80,274	$ 76,304	3,970
Future tax reduction	$ (142,945)	$ (71,925)	(71,020)
Depletion, depreciation, amortization and accretion	$ 619,032	$ 637,377	(18,345)
Other non-cash (income) expenses	$ 44,482	$ (26,864)	71,346
EBITDA	$ 685,696	$1,010,742	$(325,046)
Total debt excluding convertible debentures to EBITDA	1.6	1.6	
Total debt including convertible debentures to EBITDA	1.7	1.7	
Total Capitalization excluding convertible debentures[(2)]	$3,860,346	$4,188,308	$(327,962)
Total Capitalization including convertible debentures	$3,935,174	$4,263,223	$(328,049)
Total debt excluding convertible debentures as a percentage of total capitalization	29.1%	38.1%	(9.0%)
Total debt including convertible debentures as a percentage of total capitalization	30.5%	39.2%	(8.7%)

(1) Non-current portion of long term debt.

(2) Total capitalization includes total debt plus Unitholders Equity. (Total debt excludes working capital deficit but includes the current portion of long term debt).

During 2009 total debt excluding convertible debentures decreased $470.1 million. The largest decline was due to the issuance of 28.8 million Trust Units in October 2009. The net proceeds of approximately $285.0 million repaid existing indebtedness under Pengrowth s credit facilities. Despite this reduction, the total debt excluding convertible debentures to EBITDA ratio at the end of 2009 was unchanged relative to last year as a result of lower EBITDA realizations.

Table of Contents

At December 31, 2009 Pengrowth had total available credit of $1.2 billion. The largest source of accessible credit was a $1.2 billion committed term credit facility provided by a syndicate of 11 Canadian and foreign banks. This facility expires on June 15, 2011 and at December 31, 2009 was reduced by drawings of $60 million and outstanding letters of credit of $18 million. Pengrowth also maintains a $50 million demand operating line with one Canadian bank from which $11 million of drawings and $5 million of outstanding letters of credit was drawn.

In 2010, Pengrowth expects to fund distributions declared and capital expenditures with cash flow from operations. The undrawn portion of the credit facility together with long term debt and equity capital markets are expected to provide Pengrowth with the flexibility required to pursue growth and acquisition opportunities as they arise during the year.

Pengrowth s senior unsecured notes and credit facilities are subject to a number of covenants, all of which were met throughout the year and at December 31, 2009.

The calculation for each financial covenant is based on specific definitions, is not in accordance with GAAP and cannot be readily replicated by referring to Pengrowth s financial statements. The financial covenants are substantially similar between the credit facilities and the senior unsecured notes.

Key financial covenants are summarized below:

1. Total senior debt must not exceed three times EBITDA for the last four fiscal quarters;

2. Total debt must not exceed 3.5 times EBITDA for the last four fiscal quarters;

3. Total senior debt must be less than 50 percent of total book capitalization;

4. EBITDA must not be less than four times interest expense.

Failing a financial covenant may result in one or more of Pengrowth s loans being in default. In certain circumstances, being in default of one loan will, absent a cure, result in other loans also being in default. In the event that non compliance continued Pengrowth would have to either repay the debt, refinance the debt or negotiate new terms with the debt holders and may have to suspend distributions to unitholders.

Management monitors capital using primarily total debt to the trailing twelve months earnings before interest, taxes, depletion, depreciation, amortization, accretion, and other non-cash items (EBITDA) and Total Debt to Total Capitalization. Pengrowth seeks to manage the ratio of total debt to trailing EBITDA and Total Debt to Total Capitalization ratio with the objective of being able to finance its growth strategy while maintaining sufficient flexibility under the debt covenants. However, there may be instances where it would be acceptable for total debt to trailing EBITDA to temporarily fall outside of the normal targets set by management such as in financing an acquisition to take advantage of growth opportunities. In the event of a significant acquisition certain credit facility financial covenants are relaxed for two fiscal quarters after the close of the acquisition. Pengrowth may prepare pro forma financial statements for debt covenant purposes and has additional flexibility under its debt covenants for a set period of time. This would be a strategic decision recommended by management and approved by the Board of Directors with steps taken in the subsequent period to restore Pengrowth s capital structure based on its capital management objectives.

If certain financial ratios reach or exceed certain levels, management may consider steps to improve these ratios. These steps may include, but are not limited to, raising equity, property dispositions, reducing capital expenditures or distributions. Details of these measures are included in Note 19 to the consolidated financial statements.

All loan agreements are filed on SEDAR as Other or Material document .

Pengrowth is continuing to evaluate its re-financing options around the upcoming maturity of U.S. $150 million of senior unsecured notes in April 2010. If Pengrowth elects not to re-finance this note in the private placement debt market it may utilize its revolving credit facility or issue equity as a means to repay the notes.

Pengrowth has implemented an Equity Distribution Program which permitted the distribution of up to 25,000,000 trust units from time to time at prevailing market prices until January of 2010 through the New York Stock Exchange (NYSE) or the Toronto Stock Exchange (TSX). During the third and fourth quarters of 2009, 1,169,900 trust units were issued under the Equity Distribution Program for net proceeds of approximately US$9.9 million on the NYSE.

Regulatory approval permitting the distribution under the Equity Distribution Program was allowed to expire in January 2010 and may be reinstated at any time.

Unitholders are eligible to participate in the Distribution Reinvestment Plan (DRIP). DRIP entitles the unitholder to reinvest cash distributions in additional units of the Trust. The trust units under the plan are issued from treasury at a five percent discount to the weighted average closing price of all trust units traded on the TSX for the 20 trading days preceding a distribution payment date.

For the period ended December 31, 2009, 3.0 million trust units were issued for cash proceeds of $26.3 million under the DRIP compared to 3.7 million trust units for cash proceeds of $59.4 million at December 31, 2008.
At December 31, 2009 Pengrowth had $74.8 million of 6.5 percent convertible unsecured subordinated debentures (the debentures) outstanding. The debentures were scheduled to mature on December 31, 2010. However, on December 16, 2009 Pengrowth announced its intention to redeem the debentures on January 15, 2010. The debentures were redeemed for total consideration of $76.8 million including accrued interest to the redemption date. This transaction was funded through incremental borrowing from its credit facilities which are recorded as long term debt.
Pengrowth does not have any off balance sheet financing arrangements.

Financial Instruments

Financial instruments are utilized by Pengrowth to manage its exposure to commodity price fluctuations, foreign currency and interest rate exposures. Pengrowth s policy is not to utilize financial instruments for trading or speculative purposes. Please see Note 2 to the financial statements for a description of the accounting policies for financial instruments. Please see Note 20 to the financial statements for additional information regarding market risk, credit risk, liquidity risk and fair value of Pengrowth s financial instruments.

Cash Flow and Distributions

The following table provides cash flow from operating activities, net income and distributions declared with the excess (shortfall) over distributions and the ratio of distributions declared over cash flow from operating activities:

($ thousands, except per trust unit amounts and ratios)	Three months ended			Twelve months ended	
	Dec 31, 2009	Sept 30, 2009	Dec 31, 2008	**Dec 31, 2009**	Dec 31, 2008
Cash flow from operating activities	**149,933**	162,915	154,807	**551,350**	912,516
Net income	**50,523**	78,290	148,688	**84,853**	395,850
Distributions declared	**60,880**	72,235	144,663	**287,853**	651,015
Distributions declared per trust unit	**0.21**	0.27	0.57	**1.08**	2.59
Excess of cash flow from operating activities over distributions declared	**89,053**	90,680	10,144	**263,497**	261,501
Per trust unit	**0.32**	0.35	0.04	**1.00**	1.05
(Shortfall) Surplus of net income (loss) over distributions declared	**(10,357)**	6,055	4,025	**(203,000)**	(255,165)
Per trust unit	**(0.04)**	0.02	0.02	**(0.77)**	(1.02)
Ratio of distributions declared over cash flow from operating activities	**41%**	44%	93%	**52%**	71%

Distributions typically exceed net income as a result of non-cash expenses which may include unrealized losses on commodity risk; depletion, depreciation, and amortization; future income tax expense; trust unit based compensation; and accretion. These non-cash expenses result in a reduction to net income, with no impact to cash flow from operating activities. Accordingly, we expect that distributions will exceed net income in most periods. In most periods, we would expect distributions plus capital expenditures to not exceed cash flow from operating activities. In the event distributions plus capital expenditures exceed cash flow from operating activities, the shortfall would be funded by available bank facilities. The most likely circumstance for this to occur would be where there is a significant negative impact to working capital during the reporting period. Pengrowth s goal over longer periods is to maintain or modestly grow production and reserves on a debt adjusted per unit basis.

As a result of the depleting nature of Pengrowth s oil and gas assets, capital expenditures are required to offset production declines while other capital is required to maintain facilities, acquire prospective lands and prepare future projects. Capital spending and acquisitions may be funded by the excess of cash flow from operating activities over distributions declared, through additional debt or the issuance of equity. Pengrowth does not deduct capital expenditures when calculating cash flow from operating activities. However, Pengrowth does deduct costs associated with environmental activities when calculating cash flow from operating activities.

Table of Contents

Notwithstanding the fact that cash flow from operating activities normally exceeds distributions, the difference has historically not been sufficient to fund the capital spending required to fully replace production. To fully replace production would require additional capital which would be funded by additional amounts withheld from distributions, equity or a combination of equity and debt. Accordingly, Pengrowth believes our distributions include a return of capital. Forecasted capital spending in 2010 of $285 million, before drilling credits, will not be sufficient to fully replace the oil and gas reserves Pengrowth expects to produce during the year. If the produced reserves are not replaced in the future by successful capital programs or acquisitions, future distributions could be impacted.

Pengrowth has historically paid distributions at a level that includes a portion which is a return of capital to its investors. From time to time Pengrowth may issue additional trust units to repay debt, fund capital programs and acquisitions. Investors can elect to participate in the distribution re-investment program.

Cash flow from operating activities is derived from producing and selling oil, natural gas and related products. As such, cash flow from operating activities is highly dependent on commodity prices. Pengrowth entered into forward commodity contracts to mitigate price volatility and to provide a measure of stability to monthly cash flow. Details of commodity contracts are contained in Note 20 to the financial statements.

The board of directors and management regularly review the level of distributions. The board considers a number of factors, including expectations of future commodity prices, capital expenditure requirements, and the availability of debt and equity capital. As a result of the volatility in commodity prices, changes in production levels and capital expenditure requirements, there can be no certainty that Pengrowth will be able to maintain current levels of distributions and distributions can and may fluctuate in the future. To maintain its financial flexibility, Pengrowth reduced its monthly distributions three times between March 31, 2008 and December 31, 2009 from $0.225 per trust unit, to $0.17 per trust unit, to $0.10 per trust unit, to $0.07 per trust unit. In the current production and price environment, the possibility of suspending distributions in the near future is unlikely, but the amount may vary. Pengrowth has no restrictions on the payment of its distributions other than maintaining its financial covenants in its borrowings.

Cash distributions are generally paid to unitholders on or about the 15th day of the second month following the month of production. Pengrowth paid $0.24 per trust unit as cash distributions during the fourth quarter of 2009. Pengrowth declared distributions related to fourth quarter production of $0.21 per trust unit.

Taxability of Distributions

In 2009, 100 percent of Pengrowth s 2009 distributions and 100 percent of 2010 distributions are anticipated to be taxable to Canadian residents.

Pengrowth amended its U.S. tax entity election to be classified as a corporation for U.S. federal income tax purposes effective July 1, 2009. Distributions paid to U.S. residents for the first six months of 2009 will be treated as partnership distributions for U.S. federal tax purposes and will be treated as dividends starting with the July 15th distribution. Distributions to U.S. residents are currently subject to a 15 percent Canadian withholding tax. On September 21, 2007, Canada and the United States signed the fifth protocol of the Canada-United States Tax Convention (the Protocol) which increases the amount of Canadian withholding tax from 15 percent to 25 percent on distributions of income from a partnership. The increase became effective on and after January 1, 2010, which was one of the reasons prompting Pengrowth to change its election on July 1, 2009, and have its distributions taxed as dividends for U.S. investors. As a result the increase does not apply to corporate dividends and the withholding tax will remain at 15 percent on Pengrowth s distributions. Residents of the U.S. should consult their individual tax advisors on the impact of this change. The Canadian withholding tax rate on distributions paid to unitholders in other countries varies based on individual tax treaties.

Table of Contents

Commitments and Contractual Obligations

($ thousands)	2010	2011	2012	2013	2014	thereafter	Total
Long term debt (1)	157,650	60,000		52,550		814,404	1,084,604
Interest payments on long term debt (2)	58,080	55,489	55,489	53,573	52,614	149,368	424,613
Convertible debentures (3)(4)		79,599					79,599
Other (5)	12,935	12,695	12,489	12,359	12,141	35,383	98,002
	228,665	207,783	67,978	118,482	64,755	999,155	1,686,818
Purchase obligations							
Pipeline transportation	28,194	26,298	22,510	16,479	14,936	12,344	120,761
CO_2 purchases (6)	3,728	3,290	2,972	2,988	3,005	3,885	19,868
	31,922	29,588	25,482	19,467	17,941	16,229	140,629
Remediation trust fund payments	250	250	250	250	250	11,250	12,500
	260,837	237,621	93,710	138,199	82,946	1,026,634	1,839,947

(1) The debt repayment includes the principal owing at maturity on foreign denominated fixed rate debt. (see Note 9 of the financial statements)

(2) Interest payments relate to the interest payable on the fixed rate debt. Foreign denominated debt is translated using the year-end exchange rate.

(3) The convertible debentures were redeemed in January 2010 and repaid with amounts borrowed under the revolving credit facility. The revolving credit facility is currently scheduled to be repaid in 2011, assuming it is not renewed (see Note 9 of the financial statements).

(4) Includes annual interest on convertible debentures outstanding at year-end and assumes no conversion of convertible debentures prior to maturity.

(5) Includes office rent and vehicle leases.

(6) For the Weyburn CO_2 project, prices are denominated in U.S. dollars and have been translated at the year-end exchange rate.

Table of Contents

Summary of Trust Unit Trading Data

		High	Low	Close	Volume (000s)	Value ($ millions)
TSX	**PGF.UN ($ Cdn)**					
2009	1st quarter	12.33	5.84	7.10	30,564	252.6
	2nd quarter	9.81	6.71	9.18	26,934	233.8
	3rd quarter	11.33	7.49	11.33	28,766	269.0
	4th quarter	11.39	9.40	10.15	42,483	439.2
	Year	12.33	5.84	10.15	128,747	1,194.6
2008	1st quarter	19.82	14.16	19.67	30,755	557.9
	2nd quarter	21.56	19.17	20.50	28,004	569.7
	3rd quarter	20.55	14.73	15.99	31,735	565.4
	4th quarter	15.98	8.55	9.35	35,035	402.7
	Year	21.56	8.55	9.35	125,529	2,095.7
NYSE	**PGH ($ U.S.)**					
2009	1st quarter	10.11	4.51	5.58	28,538	195.8
	2nd quarter	9.00	5.30	7.90	27,305	205.8
	3rd quarter	10.54	6.43	10.51	23,914	203.1
	4th quarter	10.52	8.81	9.63	29,823	290.7
	Year	10.54	4.51	9.63	109,580	895.4
2008	1st quarter	19.47	13.67	19.10	14,293	257.5
	2nd quarter	21.90	18.86	20.11	19,425	392.7
	3rd quarter	20.20	14.16	14.94	26,815	457.7
	4th quarter	15.00	6.84	7.62	41,776	401.2
	Year	21.90	6.84	7.62	102,309	1,509.1

Table of Contents

Summary of Quarterly Results

The following table is a summary of quarterly information for 2009 and 2008.

2009	**Q1**	**Q2**	**Q3**	**Q4**
Oil and gas sales ($ thousands)	322,973	335,634	325,264	359,296
Net income/(loss) ($ thousands)	(54,232)	10,272	78,290	50,523
Net income/(loss) per trust unit ($)	(0.21)	0.04	0.30	0.18
Net income/(loss) per trust unit diluted ($)	(0.21)	0.04	0.30	0.18
Cash flow from operating activities ($ thousands)	94,386	144,116	162,915	149,933
Distributions declared ($ thousands)	77,212	77,526	72,235	60,880
Distributions declared per trust unit ($)	0.30	0.30	0.27	0.21
Daily production (boe)	80,284	82,171	78,135	77,529
Total production (mboe)	7,226	7,478	7,188	7,133
Average realized price ($ per boe)	44.57	44.74	45.22	50.35
Operating netback ($ per boe)	23.87	26.28	24.72	26.63

2008	Q1	Q2	Q3	Q4
Oil and gas sales ($ thousands)	457,606	550,623	518,662	392,158
Net income/(loss) ($ thousands)	(56,583)	(118,650)	422,395	148,688
Net income/(loss) per trust unit ($)	(0.23)	(0.48)	1.69	0.58
Net income/(loss) per trust unit diluted ($)	(0.23)	(0.48)	1.69	0.58
Cash flow from operating activities ($ thousands)	216,238	267,874	273,597	154,807
Distributions declared ($ thousands)	167,234	168,159	170,959	144,663
Distributions declared per trust unit ($)	0.675	0.675	0.675	0.565
Daily production (boe)	82,711	80,895	80,981	83,373
Total production (mboe)	7,527	7,361	7,450	7,670
Average realized price ($ per boe)	60.30	73.21	67.71	50.34
Operating netback ($ per boe)	33.62	42.15	37.48	26.23

In addition to natural decline, production changes over these quarters was a result of production limitations due to plant turnarounds and unscheduled maintenance in the second and third quarters of both 2009 and 2008 partly offset by a property acquisition in the fourth quarter of 2008. Changes in commodity prices have affected oil and gas sales, which have been partially muted by risk management activity to mitigate price volatility and to provide a measure of stability to monthly cash flow. Net income (loss) in 2009 and 2008 has been impacted by non-cash charges, in particular depletion, depreciation and amortization, accretion of ARO, unrealized mark-to-market gains and losses, unrealized foreign exchange gains and losses, and future taxes. Cash flow has not been impacted by the non-cash charges, however it does reflect the impact of changes in operating and general and administrative costs.

Selected Annual Information

The table below provides a summary of selected annual financial information for the years ended 2009, 2008, and 2007.

	Twelve months ended December 31		
($ thousands)	2009	2008	2007

Oil and gas sales	1,343,167	1,919,049	1,722,038
Net income	84,853	395,850	359,652
Net income per trust unit ($)	0.32	1.58	1.47
Net income per trust unit diluted ($)	0.32	1.58	1.46
Distributions declared per trust unit ($)	1.08	2.59	2.88
Total assets	4,693,604	5,317,341	5,234,251
Long term debt[(1)]	982,427	1,599,418	1,278,266
Trust unitholders equity	2,795,201	2,663,805	2,756,220
Number of trust units outstanding at year end (thousands)	289,835	256,076	246,846

(1) Includes long term debt and convertible debentures.

Oil and gas sales for 2009 decreased as a result of lower prices for all commodities through the year as well as lower production

27

volumes primarily due to natural decline. Higher realized commodity prices for the first three quarters of 2008 were the main contributor to higher oil and gas sales values compared to 2007. Net income and distributions declared are strongly linked to oil and gas sales. Long term debt is lower at December 31, 2009 than prior periods due to approximately $285 million of net proceeds from the fourth quarter 2009 equity issue being applied to the credit facility, as well as the US $150 million notes due April 2010 being reclassified to current liabilities.

Business Risks

The amount of distributions available to unitholders and the value of Pengrowth trust units are subject to numerous risk factors. As the trust units allow investors to participate in the net cash flow from Pengrowth s portfolio of producing oil and natural gas properties, the principal risk factors that are associated with the oil and gas business include, but are not limited to, the following influences:

The prices of Pengrowth s products (crude oil, natural gas, and NGLs) fluctuate due to many factors including local and global market supply and demand, weather patterns, pipeline transportation and political and economic stability.

Pengrowth s plan to convert to a dividend paying corporation on or before January 1, 2011, is dependent on achieving approval from shareholders.

Capital markets may restrict Pengrowth s access to capital and raise its borrowing costs. To the extent that external sources of capital become limited or cost prohibitive, Pengrowth s ability to fund future development and acquisition opportunities may be impaired.

Pengrowth is exposed to third party credit risk through its oil and gas sales, financial hedging transactions and joint venture activities. The failure of any of these counterparties to meet their contractual obligations could adversely impact Pengrowth. In response, Pengrowth has established a credit policy designed to mitigate this risk and monitors its counterparties on a regular basis.

The marketability of our production depends in part upon the availability, proximity and capacity of gathering systems, pipelines and processing facilities. Operational or economic factors may result in the inability to deliver our products to market.

Geological and operational risks affect the quantity and quality of reserves and the costs of recovering those reserves. Our actual results will vary from our reserve estimates and those variations could be material.

Government royalties, income taxes, commodity taxes and other taxes, levies and fees have a significant economic impact on Pengrowth s financial results. Changes to federal and provincial legislation governing such royalties, taxes and fees, including implementation of the SIFT Legislation, could have a material impact on Pengrowth s financial results and the value of Pengrowth trust units.

Pengrowth could lose its grandfathered status under the SIFT Legislation and become subject to the SIFT tax prior to January 1, 2011 if it exceeds the normal growth guidelines.

Oil and gas operations carry the risk of damaging the local environment in the event of equipment or operational failure. The cost to remediate any environmental damage could be significant.

Environmental laws and regulatory initiatives impact Pengrowth financially and operationally. We may incur substantial capital and operating expenses to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with future regulations to reduce greenhouse gas and other emissions.

Pengrowth s oil and gas reserves will be depleted over time and our level of cash flow from operations and the value of our trust units could be reduced if reserves and production are not replaced. The ability to replace production depends on the amount of capital invested and success in developing existing reserves, acquiring new reserves and financing this development and acquisition activity within the context of the capital markets.

Increased competition for properties could drive the cost of acquisitions up and expected returns from the properties down.

Timing of oil and gas operations is dependent on gaining timely access to lands. Consultations, that are mandated by governing authorities, with all stakeholders (including surface owners, First Nations and all interested parties) are becoming increasingly time consuming and complex, and are having a direct impact on cycle times.

A significant portion of Pengrowth s properties are operated by third parties whereby Pengrowth has less control over the pace of capital and operating expenditures. If these operators fail to perform their duties properly, or become insolvent, we may experience interruptions in production and revenues from these properties or incur additional liabilities and expenses as a result of the default of these third party operators.

During periods of increased activity within the oil and gas sector, the cost of goods and services may increase and it may be more difficult to hire and retain professional staff.

Changing interest rates influence borrowing costs and the availability of capital.

Failing a financial covenant may result in one or more of Pengrowth s loans being in default. In certain circumstances, being in default of one loan will result in other loans to also be in default. In the event that non compliance continued Pengrowth would have to either repay the debt, refinance the debt or negotiate new terms with the debt holders and may have to suspend distributions to unitholders.

Changes to accounting policies, including the implementation of IFRS may result in significant adjustments to equity and/or net income which could increase the risk of failing a financial covenant contained within Pengrowth s lending agreements.

Investors interest in the oil and gas sector may change over time which would affect the availability of capital and the value of Pengrowth trust units.

Inflation may result in escalating costs, which could impact unitholder distributions and the value of Pengrowth trust units.

Canadian / U.S. exchange rates influence revenues and, to a lesser extent, operating and capital costs. Pengrowth is also exposed to foreign currency fluctuations on the U.S. dollar denominated notes for both interest and principal payments.

The value of Pengrowth trust units is impacted directly by the related tax treatment of the trust units and the trust unit distributions, and indirectly by the tax treatment of alternative equity investments. Changes in Canadian or U.S. tax legislation could adversely affect the value of our trust units. As 2011 approaches, the expectation of taxability of distributions may negatively impact the value of trust units.

Pengrowth s recently announced change to its value creation strategy, including increasing levels of capital re-investment on our existing assets, may not yield the expected benefits and result in expected value creation. Drilling opportunities may prove to be more costly or less productive than anticipated. In addition, the dedication of a larger percentage of our cash flow to such opportunities may reduce the funds available for distribution to unitholders. In such event, the market value of the trust units may be adversely effected.

Attacks by individuals against facilities and the threat of such attacks may have an adverse impact on Pengrowth and the implementation of security measures as a precaution against possible attacks would result in increased cost to Pengrowth s business.

Substantial and sustained reductions in commodity prices or equity markets, including Pengrowth s unit price, in some circumstances could result in Pengrowth reducing the recorded book value of some of its assets.

Delays in business operations could adversely affect Pengrowth s distributions to unitholders and the market price of the trust units.

These factors should not be considered exhaustive. Additional risks are outlined in the AIF of the Trust available on SEDAR at www.sedar.com.

Subsequent Events

On January 14, 2010, Pengrowth redeemed all of its outstanding Convertible Unsecured Subordinated Debentures. The cash redemption amount of approximately $76.8 million, including a redemption premium and accrued interest to the redemption date, was funded with incremental borrowings from the revolving credit facility.

On February 17, 2010, Pengrowth completed a disposition of certain royalty interests for proceeds, net of adjustments, of approximately $39 million.

On February 19, 2010, Monterey issued additional equity in a public offering through which Pengrowth purchased 952,500 shares of Monterey for approximately $4.0 million and continues to own approximately 20 percent of the outstanding common shares subsequent to the share purchase.

Outlook

At this time, Pengrowth s 2010 capital program is forecast to deliver average daily production volumes of between 74,000 and 76,000 boe per day. This estimate excludes the impact from any potential future acquisitions and dispositions.

Operating costs are anticipated to be $395 million for the full year 2010; however, per boe operating costs are estimated to increase to $14.40 per boe. The expected increase in per boe operating costs is primarily attributed to lower production in 2010.

Royalty expense for 2010 is now forecasted to be approximately 21 percent of Pengrowth s sales excluding the impact of commodity risk management contracts.

The G&A expenses are expected to be flat or slightly lower in 2010 compared to 2009. On a per boe basis, G&A expenses are anticipated to be $2.23 per boe for the full year 2010. This estimate includes costs expected to be incurred in 2010 associated with Pengrowth s anticipated conversion from a trust to a dividend paying corporation on or before January 1, 2011.

The 2010 capital spending is anticipated to be $285 million, before drilling royalty credits, and is designed to replace a portion of production while retaining cash flow for production additions through acquisitions. The forecast level of capital expenditures is expected to be funded entirely from cash flow from operations.

Pengrowth expects to spend approximately $20.0 million for 2010 on remediation and abandonment, excluding contributions to remediation trust funds.

Pengrowth s approach for 2010 will be that of cautious optimism. Pengrowth will continue to live within its means; namely that capital spending plus distributions will not normally exceed cash flow from operating activities. Entering into 2010, approximately 34 percent of expected 2010 liquids production are hedged at $82.09 per bbl and 45 percent of expected 2010 natural gas volumes at $6.13 per mmbtu, which management believes is at a reasonable level to mitigate some price risk in a highly volatile price environment. Pengrowth s credit facilities together with debt and equity markets are expected to provide Pengrowth with the flexibility to pursue growth opportunities that may arise in 2010.

Current Global Economic Conditions

Towards the end of 2008, the global economic environment deteriorated rapidly and resulted in a very challenging time for commodity prices, the capital markets and equity values. In the earlier part of 2009, these same challenges were present with commodity prices decreasing and access to equity and credit markets uncertain. The impact on Pengrowth of the global recession was evident in significantly lower cash flow from operating activities which prompted decreases in distributions and capital spending in 2009. Debt reduction was a major focus in 2009. In addition, hedging continued to be utilized to mitigate some of the commodity price risk and create a level of stability to cash flow.

In the latter part of 2009, the economy began to show signs of recovery with commodity prices stabilizing and increasing in the fourth quarter, and access to equity and credit markets available again. As the capital markets showed signs of recovery through the fourth quarter of 2009, Pengrowth issued equity resulting in net proceeds of approximately $285 million which was applied to reduce debt and for general corporate purposes. Management and the Board of Directors will continue to evaluate both capital expenditures and distribution levels within the context of economic and commodity price outlooks.

International Financial Reporting Standards (IFRS)

Publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS), in full and without modification, in place of Canadian GAAP for interim and annual periods beginning on or after January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Pengrowth for the year ended December 31, 2010, including the opening IFRS balance sheet as of

January 1, 2010.

Table of Contents

Pengrowth commenced its IFRS conversion project in 2008 and has established a formal governance structure. This structure includes a full time IFRS Project Coordinator, a steering committee consisting of senior members of the finance team on an ongoing basis and includes information technology, treasury and operations personnel as required. Pengrowth has also engaged an external expert advisory firm. Regular IFRS project reporting is provided to senior management and to the Audit Committee of the Board of Directors.

IFRS Project Plan

Pengrowth s project consists of four phases: diagnostic; design and planning; solution development; and implementation.

Diagnostic This phase involves performing a high-level review of the major differences between Canadian GAAP and IFRS and to identify information technology and business processes that may be impacted by the transition to IFRS.

Status The diagnostic analysis was completed in mid-2008.

Design and planning The results of the diagnostic were ranked according to complexity, time to complete and potential impact on the financial position and results of operations. A detailed plan was developed in order to address the issues identified and ranked in the diagnostic phase. The planning is updated and progress is reported to the Audit Committee on a regular basis.

Status Pengrowth completed the initial design and planning in mid-2009. The planning is updated and progress is reported to the Audit Committee of the board of Directors on a regular basis.

Solution development In this phase, items identified in the diagnostic phase are addressed according to the priority assigned. This phase involves detailed analysis of the applicable IFRS standard in relation to current practice and development of alternative policy choices. In addition, certain potential differences are further investigated to assess whether there may be broader impact to Pengrowth s debt agreements, compensation arrangements or management reporting systems. The conclusion of the solution development phase will require the Audit Committee of the Board of Directors to review and approve significant accounting policy choices as recommended by the IFRS Steering Committee.

Status Solution development began in late 2008 for classification of exploration and evaluation expenditures, depletion, cash generating units and impairment of capital assets, share based payments, business combinations, financial instruments, trust unit-holders equity and initial adoption of IFRS. Pengrowth is currently engaged in the analysis and interpretation of provisions (including ARO), income taxes and risk sharing arrangements (farm-outs, asset swaps, etc).

Implementation Involves implementing all of the changes approved in the solution development phase and may include changes to accounting policies, information systems, business processes, modification to agreements and training of staff impacted by the conversion.

Status Implementation for information technology changes began in 2009. Training for the IFRS Steering Committee members commenced in 2008. Internal education of the Audit Committee and key financial and accounting personnel began in the fourth quarter of 2009. Detailed implementation meetings involving internal personnel directly affected by IFRS also began in the fourth quarter of 2009. Continued training and implementation meetings are expected throughout 2010.

Management has not yet finalized its accounting policies and as such is unable to quantify the impact of adopting IFRS on the financial statements. In addition, due to anticipated changes to IFRS prior to Pengrowth s adoption of IFRS, management s plan and accounting policy decisions are subject to change based on new facts and circumstances that arise after the date of this MD&A.

First-Time Adoption of IFRS

IFRS 1, First-Adoption of International Financial Accounting Standards (IFRS), sets out the procedures that an entity must follow when it adopts IFRS for the first time as the basis for preparing its general purpose financial statements.

In addition, IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement of full retrospective application of IFRS.

Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for Pengrowth. The most significant of these exemptions and exceptions are currently expected to be as follows:

Business Combinations IFRS 1 would allow Pengrowth to adopt the IFRS policies for business combinations on a prospective basis rather than retrospectively restating all prior business combinations. The IFRS policies for business combinations are converged with the new CICA Handbook section 1582 that are effective for Pengrowth on January 1, 2011; however, early adoption under Canadian GAAP is permitted.

Property, Plant and Equipment (PP&E) IFRS 1 provides the option to value PP&E at deemed cost rather that retrospective restatement upon the adoption of IFRS. Currently, Pengrowth accumulates all oil and gas assets into one cost center. Under IFRS, Pengrowth s oil and gas assets must be divided into smaller cost centers. Pengrowth may choose to allocate the net book value of the full cost oil and gas assets as the deemed cost of the new cost centers on the basis of Pengrowth`s reserve volumes or reserve values at the adoption date. Alternatively, Pengrowth could elect to record PP&E at fair value on the date of transition. Under either alternative, historical cost accounting would continue under IFRS.

IFRS differences

Pengrowth has completed analysis of the significant accounting policies and has identified the key differences that may impact the financial statements as follows:

Reclassification of Exploration and Evaluations (E&E) expenditures Upon transition to IFRS, Pengrowth will reclassify E&E expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. This will be comprised of the book value of Pengrowth s unproven properties that are currently excluded from Depletion (see note 6 to the audited annual financial statements). E&E assets will not be depleted but must be assessed for impairment when there are indicators for possible impairment, such as allowing the mineral rights lease to expire or a decision to no longer pursue exploration and evaluation of a specific E&E asset.

Impairment of PP&E assets Impairment of PP&E is currently assessed at a consolidated level. Under IFRS, impairment of PP&E must be assessed at a more detailed level. Impairment calculations will be performed at the Cash Generating Unit level, using the greater of fair value less costs to sell or the value in use. This may result in more frequent impairments of assets under IFRS.

Calculation of Depletion Expense Pengrowth currently calculates depletion of oil and gas assets on a consolidated basis based on total production and total proved reserves. Under IFRS, depletion will be calculated at a more detailed level and at least at the level of cash generating unit. In addition, under IFRS Pengrowth may use either total proven reserves or total proven plus probable reserves for the depletion calculation. The significance of the change in depletion is not known and is primarily dependant on the possible changes to the reserve base used in the calculation of depletion.

Trust Unit-Holders Equity It is uncertain if Pengrowth s trust units would qualify for classification as equity under IFRS due to specific features of the trust indenture, including the redemption provisions. If unable to qualify for classification as equity, Pengrowth trust units would be classified as liabilities on the balance sheet.

Provisions In January 2010, the International Accounting Standards Board (IASB) released a re-exposure draft for certain aspects of the standards for provisions. A final new standard for ARO and other provisions is expected to be released in the second half of 2010. Under current IFRS standards, the net present value of the Asset Retirement Obligations (ARO) as reported balance sheet may be calculated differently despite the estimated future expenditures being unchanged. It is unclear if the discount rate used would be based on a credit adjusted rate, as it currently is, or based on a risk free rate. A change in the discount rate would materially change the amount recorded on the balance sheet. In addition, if Pengrowth allocated Canadian GAAP net book value to the IFRS cost centers, any revision to ARO would be recorded directly in equity.

Income Tax In November 2009 the IASB withdrew an exposure draft on Income Taxes. Current IFRS income tax requirements are fundamentally consistent with current practice. Any changes to Income Tax reporting are expected to be predominantly caused by changes in the book value of assets and changes in tax rates applied, not due to the change in

Income Tax accounting methodology. Revisions to Income Tax accounting standards are expected to be re-exposed by the IASB in the second half of 2010.

In addition to the accounting policy differences, Pengrowth s transition to IFRS will impact the internal controls over financial reporting, the disclosure controls and procedures, and IT systems as follows:

Internal controls over financial reporting As the review of Pengrowth s accounting policies is completed, an assessment will be made to determine changes required for internal controls over financial reporting. For example, additional controls will be implemented for the IFRS 1 changes and preparation of comparative information. This will be an ongoing process in 2010 to ensure that changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

Disclosure controls and procedures Throughout the transition process, Pengrowth will be assessing stakeholders information requirements and will ensure that adequate and timely information is provided so that stakeholders are kept apprised.

IT Systems Pengrowth has completed most of the system modifications required for IFRS reporting. Pengrowth s IT systems did not require significant modifications in order to track PP&E and E&E at a more detailed level for financial reporting. We are also currently implementing solutions to allow Pengrowth to account for certain transactions and prepare Canadian GAAP and IFRS financial statements in 2010. Additional systems modifications may be required.

Pengrowth continues to make progress on its IFRS convergence plan and management believes that Pengrowth will be in a position to prepare IFRS financial statements in the first quarter of 2011. Pengrowth has not made any final determination as to what options it may select upon conversion to IFRS, and differences in reporting under some options may be significantly different. The final decisions are subject to the approval of Pengrowth s Audit Committee and Board of Directors and the concurrence of Pengrowth s auditors. Pengrowth continues to monitor the IFRS adoption efforts of many of its peers and participates in related processes, as appropriate. Pengrowth is currently involved in an IFRS working group composed of intermediate to large oil and gas producers and an IFRS and Financial Reporting group consisting of a peer group of income trusts.

Recent Accounting Pronouncements

New Canadian accounting recommendations related to goodwill and intangible assets which established revised standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets were adopted on January 1, 2009. There was no impact on the financial position or results of operations as a result of adopting this standard.

New Canadian accounting standards related to financial instruments have been issued which require enhanced disclosure relating to the fair value of financial instruments and the liquidity risk associated with financial instruments were adopted on December 31, 2009. The new standards require that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to Note 20 for enhanced fair value disclosures.

New Canadian accounting standards related to business combinations have been issued which will require changes to the way business combinations are accounted. The new standards broaden the scope of business combinations and require transaction costs to be expensed as incurred. The new standards also require contingent liabilities to be recorded at fair value on acquisition and subsequently re-measured each reporting period until settled. The new standards require negative goodwill to be recognized in net income which is different from the current standard of deducting the amount from the non-current assets in the purchase price allocation. In addition, the consideration paid in a business combination is based on the fair value of the shares exchanged at the market price on the acquisition date. Under the current standards, the consideration paid was based on the market price of the shares before and after the date the acquisition was announced and agreed upon. The fair value of any contingent consideration is recognized on the acquisition date with subsequent changes to the consideration measured each reporting period until the amount is settled. The new Canadian standards are required for all business combinations occurring on or after January 1, 2011 although early adoption is allowed. Pengrowth is currently assessing the impact of the new standard.

Disclosure Controls and Procedures

As a Canadian reporting issuer with securities listed on both the TSX and the NYSE, Pengrowth is required to comply with Multilateral Instrument 52-109 Certification of Disclosure in Issuers Annual and Interim Filings, as well as the Sarbanes Oxley Act (SOX) enacted in the United States. Both the Canadian and U.S. certification rules include similar requirements where both the CEO and the Chief Financial Officer (CFO) must assess and certify as to the effectiveness of the disclosure controls and procedures as defined in Canada by Multilateral Instrument 52-109 Certification of Disclosure in Issuers Annual and Interim Filings and in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended.

Table of Contents

The CEO, Derek Evans, and the CFO, Christopher Webster, evaluated the effectiveness of Pengrowth s disclosure controls and procedures for the period ending December 31, 2009. This evaluation considered the functions performed by its Disclosure Committee, the review and oversight of all executive officers and the board, as well as the process and systems in place for filing regulatory and public information. Pengrowth s established review process and disclosure controls are designed to provide reasonable assurance that all required information, reports and filings required under Canadian securities legislation and United States securities laws are properly submitted and recorded in accordance with those requirements.

Based on that evaluation, the CEO and CFO concluded that the design and operation of our disclosure controls and procedures were effective at the reasonable assurance level as at December 31, 2009, to ensure that information required to be disclosed by us in reports that we file under Canadian and U.S. securities laws is gathered, recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws and is accumulated and communicated to the management of Pengrowth Corporation, including the CEO and CFO, to allow timely decisions regarding required disclosure as required under Canadian and U.S. securities laws.

It should be noted that while Pengrowth s Chief Executive Officer and Chief Financial Officer believe that Pengrowth s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that Pengrowth 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.

Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended and in Canada as defined in Multilateral Instrument 52-109 Certification of Disclosure in Issuers Annual and Interim Filings. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with accounting principles generally accepted in Canada and reconciling to accounting principles generally accepted in the U.S. for note disclosure purposes. Our internal control over financial reporting includes those policies and procedures that: pertain to the maintenance of records that in reasonable detail accurately and fairly reflect our transactions and disposition of the assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of our assets are being made only in accordance with authorizations of our management and directors; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our 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.

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this evaluation, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of internal control over financial reporting as of December 31, 2009 was audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included with our audited consolidated financial statements for the year ended December 31, 2009. No changes were made to our internal control over financial reporting during the year ending December 31, 2009 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

Table of Contents

APPENDIX C

CONSOLIDATED FINANCIAL STATEMENTS OF PENGROWTH ENERGY TRUST INCLUDING MANAGEMENT S REPORT TO UNITHOLDERS, THE AUDITORS REPORTS AND NOTE 24 THEREOF WHICH INCLUDES A RECONCILIATION OF THE CONSOLIDATED FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

MANAGEMENT S REPORT TO UNITHOLDERS

Management s Responsibility to Unitholders

The financial statements are the responsibility of the management of Pengrowth Energy Trust. They have been prepared in accordance with generally accepted accounting principles, using management s best estimates and judgments, where appropriate.

Management is responsible for the reliability and integrity of the financial statements, the notes to the financial statements, and other financial information contained in this report. In preparation of these statements, estimates are sometimes necessary because a precise determination of certain assets and liabilities is dependant on future events. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying financial statements.

Management is also responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board is assisted in exercising its responsibilities through the Audit Committee of the Board, which is composed of four non-management directors. The Committee meets periodically with management and the auditors to satisfy itself that management s responsibilities are properly discharged, to review the financial statements and to recommend approval of the financial statements to the Board.

KPMG LLP, the independent auditors appointed by the unitholders, have audited Pengrowth Energy Trust s consolidated financial statements in accordance with generally accepted auditing standards and provided an independent professional opinion. The auditors have full and unrestricted access to the Audit Committee to discuss the audit and their related findings as to the integrity of the financial reporting process.

(signed) *Derek W. Evans*	(signed) *Christopher G. Webster*
President and Chief Executive Officer	Chief Financial Officer

March 8, 2010

Table of Contents

AUDITORS REPORT

To the Unitholders of Pengrowth Energy Trust

We have audited the consolidated balance sheets of Pengrowth Energy Trust (the Trust) as at December 31, 2009 and 2008 and the consolidated statements of income and deficit, and cash flows for the years then ended. These financial statements are the responsibility of the Trust s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2009 and 2008 and the results of its operations and its cash flows for each of the years then ended in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust s internal control over financial reporting as of December 31, 2009 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 8, 2010 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

(signed) *KPMG LLP*
Chartered Accountants
Calgary, Canada
March 8, 2010

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Pengrowth Corporation, as administrators of Pengrowth Energy Trust and the Unitholders of Pengrowth Energy Trust

We have audited Pengrowth Energy Trust s (the Trust) internal control over financial reporting as of December 31, 2009 based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report to the Unitholders. Our responsibility is to express an opinion on the Trust s internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009 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 in accordance with the standards of the Public Trust Accounting Oversight Board (United States). Our report dated March 8, 2010, expressed an unqualified opinion on those consolidated financial statements.

(signed) *KPMG LLP*
Chartered Accountants
Calgary, Canada
March 8, 2010

Table of Contents

PENGROWTH ENERGY TRUST
CONSOLIDATED BALANCE SHEETS
(Stated in thousands of dollars)

	As at December 31 2009	As at December 31 2008
ASSETS		
CURRENT ASSETS		
Accounts receivable	$ 182,342	$ 197,131
Due from Pengrowth Management Limited		623
Fair value of risk management contracts (Note 20)	14,001	122,841
Future income taxes (Note 11)	969	
	197,312	320,595
FAIR VALUE OF RISK MANAGEMENT CONTRACTS (Note 20)		41,851
OTHER ASSETS (Note 5)	46,027	42,618
PROPERTY, PLANT AND EQUIPMENT (Note 6)	3,789,369	4,251,381
GOODWILL	660,896	660,896
TOTAL ASSETS	$ 4,693,604	$ 5,317,341
LIABILITIES AND UNITHOLDERS EQUITY		
CURRENT LIABILITIES		
Bank indebtedness	$ 11,563	$ 2,631
Accounts payable and accrued liabilities	185,337	260,828
Distributions payable to unitholders	40,590	87,142
Fair value of risk management contracts (Note 20)	17,555	2,706
Future income taxes (Note 11)		34,964
Contract liabilities (Note 7)	1,728	2,483
Current portion of long-term debt (Note 9)	157,546	
	414,319	390,754
FAIR VALUE OF RISK MANAGEMENT CONTRACTS (Note 20)	23,269	16,021
CONTRACT LIABILITIES (Note 7)	7,952	9,680
CONVERTIBLE DEBENTURES (Note 8)	74,828	74,915
LONG TERM DEBT (Note 9)	907,599	1,524,503
ASSET RETIREMENT OBLIGATIONS (Note 10)	288,796	344,345

FUTURE INCOME TAXES (Note 11)	181,640	293,318
TRUST UNITHOLDERS EQUITY		
Trust unitholders capital (Note 12)	4,920,945	4,588,587
Equity portion of convertible debentures (Note 8)	160	160
Contributed surplus (Note 12)	18,617	16,579
Deficit (Note 14)	(2,144,521)	(1,941,521)
	2,795,201	2,663,805
COMMITMENTS (Note 21)		
CONTINGENCIES (Note 22)		
SUBSEQUENT EVENTS (Note 23)		
TOTAL LIABILITIES AND UNITHOLDERS EQUITY	$ 4,693,604	$ 5,317,341

See accompanying notes to the consolidated financial statements.

(signed) *Thomas A. Cumming*
Director

(signed) *Wayne K. Foo*
Director

Table of Contents

PENGROWTH ENERGY TRUST
CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT
(Stated in thousands of dollars, except per trust unit amounts)

	Year ended December 31 2009	Year ended December 31 2008
REVENUES		
Oil and gas sales	$ 1,343,167	$ 1,919,049
Unrealized (loss) gain on commodity risk management (Note 20)	(173,726)	249,899
Processing and other income	15,540	15,525
Royalties, net of incentives	(207,563)	(433,970)
NET REVENUE	977,418	1,750,503
EXPENSES		
Operating	381,194	418,497
Transportation	13,467	12,519
Amortization of injectants for miscible floods	19,989	25,876
Interest on long term debt	80,274	76,304
General and administrative	62,195	58,937
Management fee (Note 17)	2,793	6,950
Foreign exchange (gain) loss (Note 15)	(149,722)	189,172
Depletion, depreciation and amortization	591,355	609,326
Accretion (Note 10)	27,677	28,051
Other expenses (income)	6,288	946
	1,035,510	1,426,578
(LOSS) INCOME BEFORE TAXES	(58,092)	323,925
Future income tax reduction (Note 11)	(142,945)	(71,925)
NET INCOME AND COMPREHENSIVE INCOME	$ 84,853	$ 395,850
Deficit, beginning of year	(1,941,521)	(1,686,356)
Distributions declared	(287,853)	(651,015)
DEFICIT, END OF YEAR	$ (2,144,521)	$ (1,941,521)
NET INCOME PER TRUST UNIT (Note 18)		
Basic	$ 0.32	$ 1.58

Diluted	$	0.32	$	1.58

See accompanying notes to the consolidated financial statements.

Table of Contents

PENGROWTH ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOW
(Stated in thousands of dollars)

	Year ended December 31	
	2009	2008
CASH PROVIDED BY (USED FOR):		
OPERATING		
Net income and comprehensive income	$ 84,853	$ 395,850
Depletion, depreciation and accretion	619,032	637,377
Future income tax reduction (Note 11)	(142,945)	(71,925)
Contract liability amortization	(2,483)	(4,664)
Amortization of injectants	19,989	25,876
Purchase of injectants	(13,298)	(21,009)
Expenditures on remediation (Note 10)	(18,042)	(32,691)
Unrealized foreign exchange (gain) loss (Note 15)	(149,233)	197,159
Unrealized loss (gain) on commodity risk management (Note 20)	173,726	(249,899)
Trust unit based compensation (Note 13)	8,125	9,998
Other items	4,248	(1,104)
Changes in non-cash operating working capital (Note 16)	(32,622)	27,548
	551,350	912,516
FINANCING		
Distributions paid (Note 14)	(334,405)	(674,993)
Bank indebtedness	8,932	2,631
Repayment of Accrete bank debt		(16,289)
Change in long term debt, net	(312,000)	148,064
Proceeds from issue of trust units	321,605	63,499
	(315,868)	(477,088)
INVESTING		
Business acquisition		(1,128)
Expenditures on property, plant and equipment	(207,451)	(401,928)
Other property acquisitions	(35,655)	(35,938)
Proceeds on property dispositions	41,885	17,361
Other investments	852	(5,000)
Change in remediation trust funds	(7,656)	(9,013)
Change in non-cash investing working capital (Note 16)	(27,457)	(1,799)
	(235,482)	(437,445)
CHANGE IN CASH AND TERM DEPOSITS		(2,017)

CASH AND TERM DEPOSITS AT BEGINNING OF YEAR		2,017
CASH AND TERM DEPOSITS AT END OF YEAR	$	$

See accompanying notes to the consolidated financial statements.

Table of Contents

PENGROWTH ENERGY TRUST
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2009 AND 2008

(Tabular amounts are stated in thousands of dollars except per trust unit amounts and as otherwise stated)

1. STRUCTURE OF THE TRUST

Pengrowth Energy Trust (the Trust) is an open-end investment trust created under the laws of the Province of Alberta pursuant to a Trust Indenture dated December 2, 1988 (as amended) between Pengrowth Corporation (Corporation) and Computershare Trust Company of Canada (Computershare). The beneficiaries of the Trust are the holders of trust units (the unitholders).

The purpose of the Trust is to directly and indirectly explore for, develop, and hold interests in petroleum and natural gas properties, through investments in securities, royalty units, net profits interests and notes issued by subsidiaries of the Trust. The activities of the Corporation are financed by issuance of royalty units, interest bearing notes to the Trust, and third party debt. The Trust, through the royalty ownership and ownership of all of the common shares, obtains substantially all the economic benefits of the Corporation. Under the terms of the Royalty Indenture, the Corporation is entitled to retain a one percent share of royalty income and all miscellaneous income (the Residual Interest) to the extent this amount exceeds the aggregate of debt service charges and general and administrative expenses. In 2009 and 2008, this Residual Interest, as computed, did not result in any income retained by the Corporation. The Trust acquired notes receivable and a Net Profits Interest (the NPI agreement or NPI) in Esprit Exploration Ltd. (Esprit) as a result of the 2006 business combination with Esprit Energy Trust (Esprit Trust). The NPI agreement entitles the Trust to monthly distributions from Esprit, a wholly owned subsidiary of the Trust. The monthly distribution is equal to the amount by which 99 percent of the gross revenue exceeds 99 percent of certain deductible expenditures as defined in the NPI agreement. The NPI agreement was terminated on December 31, 2009.

The royalty units and notes of the Corporation held by the Trust entitle it to the net income generated by the Corporation s petroleum and natural gas properties less amounts withheld in accordance with prudent business practices to provide for future operating costs and asset retirement obligations, as defined in the Royalty Indenture. In addition, unitholders are entitled to receive the net income from other investments that are held directly by the Trust.

Pursuant to the Royalty Indenture, the Board of Directors of the Corporation (the Board of Directors) can establish a reserve for certain items including up to 20 percent of gross revenue to fund future capital expenditures or for the payment of royalty income in any future period.

Pursuant to the Trust Indenture, trust unitholders are entitled to monthly distributions from interest income on the notes, royalty income under the Royalty Indenture and from other investments held directly by the Trust, less any reserves and certain expenses of the Trust including general and administrative costs as defined in the Trust Indenture.

The Board of Directors has general authority over the business and affairs of the Corporation and derives its authority in respect to the Trust by virtue of the delegation of powers by the trustee to the Corporation as Administrator in accordance with the Trust Indenture.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The Trust s consolidated financial statements have been prepared in accordance with Generally Accepted Accounting Principles (GAAP) in Canada. The consolidated financial statements include the accounts of the Trust, and all of its subsidiaries, collectively referred to as Pengrowth. All inter-entity transactions have been eliminated. Effective January 1, 2011, Pengrowth will be required to prepare consolidated financial statements in accordance with International Financial Reporting Standards.

The Corporation is a wholly owned subsidiary of the Trust and through the common shares, royalty and notes, the Trust obtains substantially all the economic benefits of Corporation. In addition, the unitholders of the Trust have the right to elect the majority of the Board of Directors of the Corporation.

Joint Interest Operations

A significant proportion of Pengrowth s petroleum and natural gas development and production activities are conducted with others and accordingly the accounts reflect only Pengrowth s interest in such activities.

Property, Plant and Equipment

Pengrowth follows the full cost method of accounting for oil and gas properties and facilities whereby all costs of developing and acquiring oil and gas properties are capitalized. These costs include lease acquisition costs, geological and geophysical expenditures, costs of drilling and completion of wells, plant and production equipment costs and related overhead charges. Pengrowth capitalizes a portion of general and administrative costs associated with exploration and development activities. In addition, transaction costs directly attributable to successful acquisitions are also capitalized.

Pengrowth excludes the cost of acquiring and evaluating certain unproved properties from the cost base subject to depletion as quantified in Note 6. Capitalized costs, including future development costs and excluding the cost of unproven properties, are depleted on a unit of production method based on total proved reserves before royalties as estimated by independent engineers. The fair value of future estimated asset retirement obligations associated with properties and facilities are capitalized and included in the depletion calculation. The associated asset retirement obligations on future development capital costs are also included in the cost base subject to depletion. Natural gas production and reserves are converted to equivalent units of crude oil using their relative energy content, as per industry standards.

Repairs and maintenance costs are expensed as incurred.

Proceeds from disposals of oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

There is a limit on the carrying value of property, plant and equipment and other assets, which may be depleted against revenues of future periods (the ceiling test). Initially, the carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, and the lower of cost and recoverable amount of unproved properties exceeds the carrying value. A separate recoverability test is completed on major development projects and unproved properties. If the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves including the lower of cost and recoverable amount of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. The carrying value of property, plant and equipment and other assets subject to the ceiling test includes asset retirement costs.

Goodwill

Goodwill, which represents the excess of the total purchase price over the estimated fair value of the net identifiable assets and liabilities acquired, is not amortized but instead is assessed for impairment annually or as events occur that could suggest impairment exists. Impairment is assessed by determining the fair value of the reporting entity and comparing this fair value to the book value of the reporting entity. If the fair value of the reporting entity is less than the book value, impairment is measured by allocating the fair value of the reporting entity to the identifiable assets and liabilities of the reporting entity as if the reporting entity had been acquired in a business combination for a purchase price equal to its fair value. Any excess of the fair value of the reporting entity over the assigned values of the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value is the impairment amount. Impairment is charged to earnings in the period in which it occurs. Goodwill is stated at cost less impairment.

Injectant Costs

Injectants (mostly natural gas and ethane) are used in miscible flood programs to stimulate incremental oil recovery. The cost of hydrocarbon injectants purchased from third parties for miscible flood projects is deferred and amortized over the period of expected future economic benefit which is currently estimated as 24 months.

Asset Retirement Obligations

Pengrowth initially recognizes the fair value of an Asset Retirement Obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit of production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed to income in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO. Management reviews the ARO estimate and changes, if any, are applied prospectively. Revisions made to the ARO estimate are recorded as an increase or decrease to the ARO liability with a corresponding entry made to the carrying amount of the related asset.

Pengrowth has placed cash in segregated remediation trust accounts to fund certain ARO for the Judy Creek properties and the Sable Offshore Energy Project (SOEP).

Income Taxes

Pengrowth follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period the change occurs. Pengrowth s policy for income tax uncertainties is that tax benefits will be recognized only when it is more likely than not the position will be sustained on examination.

Trust Unit Compensation Plans

Pengrowth has trust unit based compensation plans, which are described in Note 13. Compensation expense associated with trust unit based compensation plans is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. Pengrowth estimates the forfeiture rate of trust unit rights and deferred entitlement trust units (DEUs) at the date of grant. Any consideration received upon the exercise of trust unit based compensation together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in trust unitholders capital. Compensation expense is based on the estimated fair value of the trust unit based compensation at the date of grant.

Pengrowth does not have any outstanding trust unit compensation plans that call for settlement in cash or other assets. Grants of such items, if any, will be recorded as liabilities, with changes in the liabilities charged to net income, based on the intrinsic value.

Financial Instruments

Financial instruments are utilized by Pengrowth to manage its exposure to commodity price fluctuations, foreign currency and interest rate exposures. Pengrowth s policy is not to utilize financial instruments for trading or speculative purposes.

Financial instruments are classified into one of five categories: held for trading, held to maturity investments, loans and receivables, available for sale financial assets or other liabilities. Pengrowth has designated cash and term deposits as held for trading which are measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Investments held in the remediation trust funds have been designated as held to maturity and held for trading based on the type of investments in the fund. Other investments included in other assets have been designated as held for trading and available for sale based on the type of investment. The held for trading investment changes in fair value are recorded as unrealized gains (losses) and are included in other expenses (income) in the consolidated statements of income and deficit. The available for sale securities included in other assets are recorded at cost as the investment is in a private entity whose shares are not quoted in an active market. Held to maturity investments are measured at amortized cost, held for trading investments are measured at fair value, and available for sale investments are measured at fair value, except those whose shares are not quoted in an active market. Bank indebtedness, accounts payable and accrued liabilities, distributions payable, the debt portion of convertible debentures, and long term debt have been classified as other liabilities which are measured at amortized cost using the effective interest rate method.

All derivatives are classified as held for trading which are measured at fair value with changes in fair value over a reporting period recognized in net income. Changes in the fair value of derivatives used in certain hedging transactions for which cash flow hedge accounting is permitted would be recorded in other comprehensive income. Pengrowth does not have any risk management contracts outstanding for which hedge accounting is being applied.

Table of Contents

The receipts or payments arising from commodity contracts are recognized as a component of oil and gas sales. Unrealized gains and losses on commodity contracts are included in the unrealized gain (loss) on commodity risk management. The difference between the interest payments on the U.K. Pound Sterling denominated debt after the foreign exchange swaps and the interest expense recorded at the average foreign exchange rate is included in foreign exchange gains (losses). Unrealized gains (losses) on these swaps are included in foreign exchange gains (losses).
Comprehensive income includes net income and transactions and other events from non-owner sources such as unrealized gains and losses on effective cash flow hedges. There are no amounts that Pengrowth would include in other comprehensive income except for net income.
Transaction costs incurred in connection with the issuance of term debt instruments with a maturity of greater than one year are deducted against the carrying value of the debt and amortized to net income using the effective interest rate method over the expected life of the debt. Transaction costs incurred in connection with the issuance of other debt instruments are expensed as incurred.

Foreign Currency

The U.S. dollar and U.K. Pound Sterling denominated debt are translated into Canadian dollars at the exchange rate in effect on the balance sheet date. Foreign exchange gains and losses on the U.S. dollar and U.K. Pound Sterling denominated debt are included in income.

Equity Investment

Pengrowth utilizes the equity method of accounting for investments subject to significant influence. Under this method, investments are initially recorded at cost and adjusted thereafter to include Pengrowth s pro rata share of post-acquisition earnings. Any dividends received or receivable from the investee would reduce the carrying value of the investment.

Measurement Uncertainty

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended.
The amounts recorded for depletion, depreciation, amortization of injectants, goodwill, future income taxes and ARO are based on estimates. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. The impairment assessment of goodwill is based on the estimated fair value of Pengrowth s reporting units which is referenced to Pengrowth s unit price and the premium an arm s length party would pay to acquire all of the outstanding units. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

Net Income per Trust Unit

Basic net income per unit amounts are calculated using the weighted average number of units outstanding for the year. Diluted net income per unit amounts includes the dilutive effect of trust unit options, trust unit rights and DEUs using the treasury stock method. The treasury stock method assumes that any proceeds obtained on the exercise of in-the-money trust unit options and trust unit rights would be used to purchase trust units at the average price during the period. Diluted net income per unit amounts also include the dilutive effect of convertible debentures using the if-converted method which assumes that the convertible debentures were converted at the beginning of the period.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when the product is delivered and collection is reasonably assured. Revenue from processing and other miscellaneous sources is recognized upon completion of the relevant service.

Cash and Term Deposits

Cash and term deposits include demand deposits and term deposits with original maturities of less than 90 days.

Comparative Figures

Table of Contents

Certain comparative figures have been reclassified to conform to the presentation adopted in the current year.

3. CHANGE IN ACCOUNTING POLICIES

New Canadian accounting recommendations related to goodwill and intangible assets which established revised standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets were adopted on January 1, 2009. There was no impact on the financial position or results of operations as a result of adopting this standard.

New Canadian accounting standards related to financial instruments have been issued which require enhanced disclosure relating to the fair value of financial instruments and the liquidity risk associated with financial instruments were adopted on December 31, 2009. The new standards require that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to Note 20 for enhanced fair value disclosures.

New Canadian accounting standards related to business combinations have been issued which will require changes to the way business combinations are accounted. The new standards broaden the scope of business combinations and require transaction costs to be expensed as incurred. The new standards also require contingent liabilities to be recorded at fair value on acquisition and subsequently re-measured each reporting period until settled. The new standards require negative goodwill to be recognized in net income which is different from the current standard of deducting the amount from the non-current assets in the purchase price allocation. In addition, the consideration paid in a business combination is based on the fair value of the shares exchanged at the market price on the acquisition date. Under the current standards, the consideration paid was based on the market price of the shares before and after the date the acquisition was announced and agreed upon. The fair value of any contingent consideration is recognized on the acquisition date with subsequent changes to the consideration measured each reporting period until the amount is settled. The new Canadian standards are required for all business combinations occurring on or after January 1, 2011 although early adoption is allowed. Pengrowth is currently assessing the impact of the new standard.

4. ACQUISITIONS

2008 Acquisitions

On September 30, 2008, Pengrowth and Accrete Energy Inc. (Accrete) completed a business combination (the Combination) whereby each Accrete share was exchanged for 0.277 of a Pengrowth trust unit. As a result of the Combination, approximately 5.0 million Pengrowth trust units were issued to Accrete shareholders. The value assigned to each Pengrowth unit issued was approximately $17.95 per trust unit based on the weighted average market price of the trust units on the five days surrounding the announcement date of the Combination. In conjunction with the Combination, all of Accrete s oil and gas properties except those in the Harmattan area were transferred to Argosy Energy Inc., an unrelated company. The Combination was accounted for as an acquisition of Accrete by Pengrowth using the purchase method of accounting with the allocation of the purchase price and consideration as follows:

Allocation of Purchase Price:	
Property, plant and equipment	$ 146,463
Bank debt	(16,289)
Asset retirement obligations	(2,685)
Working capital deficit	(5,548)
Future income taxes	(31,858)
	$ 90,083
Consideration:	
Pengrowth units	$ 89,253
Acquisition costs	830
	$ 90,083

The estimated fair value of property and equipment was determined using an independent reserve evaluation. The future income tax liability was determined based on Pengrowth s effective future income tax rate of approximately 28 percent. The asset retirement obligations were determined using Pengrowth s estimated costs to remediate, reclaim and abandon the wells

Table of Contents

and facilities, the estimated timing of the costs to be incurred in future periods, an inflation rate of two percent, and a discount rate of eight percent.

The consolidated financial statements included the results of operations and cash flows from Accrete subsequent to the closing date of September 30, 2008.

5. OTHER ASSETS

	2009	2008
Remediation trust funds	$ 34,837	$ 27,122
Equity investment in Monterey Exploration Ltd.	5,039	9,872
Other investments	6,151	5,624
	$ 46,027	$ 42,618

Remediation Trust Funds

Pengrowth is required to make contributions to a remediation trust fund that is used to cover certain ARO of the Judy Creek properties. Pengrowth makes monthly contributions to the fund of $0.10 per boe of production from the Judy Creek properties and an annual lump sum contribution of $250,000. Every five years Pengrowth must evaluate the assets in the trust fund and the outstanding ARO, and make recommendations to the former owner of the Judy Creek properties as to whether contribution levels should be changed. The next evaluation is anticipated to occur in 2012. Contributions to the Judy Creek remediation trust fund may change based on future evaluations of the fund. The investment in the Judy Creek remediation trust fund is classified as held to maturity and is measured at amortized cost. Interest income is recognized when earned and included in other expenses (income). As at December 31, 2009 the value of the Judy Creek remediation trust fund was $8.8 million (December 31, 2008 - $8.7 million).

Pengrowth is required to make contributions to a remediation trust fund that will be used to fund the ARO of the SOEP properties and facilities. Pengrowth currently makes a monthly contribution to the fund of $0.52 per mcf of natural gas production and $1.04 per bbl of natural gas liquids production from SOEP. The SOEP remediation trust fund as at December 31, 2009 was $26.0 million (December 31, 2008 $18.4 million). The investments in the fund have been designated as held for trading and are recorded at fair value each period end. For the years ended December 31, 2009 and 2008, the amount of unrealized gain related to the SOEP remediation trust fund was insignificant.

The following reconciles Pengrowth s remediation trust funds for 2009 and 2008:

Remediation Trust Funds	2009	2008
Opening balance	$ 27,122	$ 18,094
Contributions to Judy Creek Remediation Trust Fund	635	816
Contributions to SOEP Environmental Restoration Fund	7,579	8,485
Remediation funded by Judy Creek Remediation Trust Fund	(558)	(288)
Change in remediation trust funds	7,656	9,013
Unrealized gain on held for trading investment [1]	59	15
Closing balance	$ 34,837	$ 27,122

(1) SOEP remediation

trust fund has
been designated
as held for
trading

Equity Investment in Monterey Exploration Ltd. (Monterey)

Pengrowth recorded a pre-tax loss of $3.7 million in 2009 to reflect Pengrowth s proportionate share of Monterey s net loss (2008 pre-tax income of $1.4 million). In addition, Pengrowth recorded a pre-tax loss of $1.1 million in 2009 (2008 $1.8 million pre-tax gain) as a result of decreases in the ownership of Monterey. The decrease in ownership was due to Pengrowth not participating in the share issuances completed by Monterey. The equity income (loss) and ownership adjustments are included in other expenses (income) on the consolidated statements of income and deficit. As of December 31, 2009, Pengrowth held approximately 8 million common shares of Monterey (December 31, 2008 8 million common shares), which is approximately 20 percent (December 31, 2008 24 percent) of the outstanding common shares. On February 19, 2010, Monterey issued additional equity in a public offering through which Pengrowth purchased 952,500 shares of Monterey

49

for approximately $4.0 million and continues to own approximately 20 percent of the outstanding common shares subsequent to the share purchase.

Other Investments

As of December 31, 2009, Pengrowth owned approximately 2.5 million shares of a public corporation valued at $1.2 million (December 31, 2008 4.2 million shares and $0.6 million respectively). The investment in the public corporation has been designated as a held for trading investment and is recorded at fair value at the end of each period.

As at December 31, 2009 and 2008, Pengrowth owned 1.0 million shares of a private corporation with a carrying value of $5.0 million. The investment has been designated as available for sale and is recorded at cost as the shares are not quoted in an active market.

6. PROPERTY, PLANT AND EQUIPMENT

	2009	2008
Property, plant and equipment, at cost	$ 7,272,408	$ 7,136,374
Accumulated depletion, depreciation and amortization	(3,498,764)	(2,907,409)
Net book value of property, plant and equipment	3,773,644	4,228,965
Net book value of deferred injectant costs	15,725	22,416
Net book value of property, plant and equipment and deferred injectants	$ 3,789,369	$ 4,251,381

In 2009, approximately $4.7 million (2008 $5.8 million) of general and administrative costs were capitalized.

As at December 31, 2009, approximately $68 million (December 31, 2008 $45 million) of capitalized costs to acquire and evaluate unproven properties has been excluded from depletion.

Pengrowth performed a ceiling test calculation at December 31, 2009 to assess the recoverable value of the property, plant and equipment. The oil and gas future prices and costs are based on the January 1, 2010 commodity price forecast of our independent reserve evaluators. These prices have been adjusted for commodity price differentials specific to Pengrowth. The following table summarizes the benchmark prices which are provided by an independent recognized valuation firm used in the ceiling test calculation. Based on these assumptions, the undiscounted value of future net revenues from Pengrowth s proved reserves exceeded the carrying value of property, plant and equipment at December 31, 2009.

Year	WTI Oil (U.S.$/bbl)	Foreign Exchange Rate (U.S.$/Cdn$)	Edmonton Light Crude Oil (Cdn$/bbl)	AECO Gas (Cdn$/mmbtu)
2010	$ 80.00	0.950	$ 83.26	$ 5.96
2011	$ 83.00	0.950	$ 86.42	$ 6.79
2012	$ 86.00	0.950	$ 89.58	$ 6.89
2013	$ 89.00	0.950	$ 92.74	$ 6.95
2014	$ 92.00	0.950	$ 95.90	$ 7.05
2015	$ 93.84	0.950	$ 97.84	$ 7.16
2016	$ 95.72	0.950	$ 99.81	$ 7.42
2017	$ 97.64	0.950	$ 101.83	$ 7.95
2018	$ 99.59	0.950	$ 103.88	$ 8.52
2019	$ 101.58	0.950	$ 105.98	$ 8.69
Thereafter		0.950		

	+ 2.0 percent/yr	+ 2.0 percent/yr	+ 2.0 percent/yr

7. CONTRACT LIABILITIES

Contract liabilities are composed of the following amounts:

Table of Contents

	2009	2008
Fixed price commodity contract	$	$ 956
Firm transportation contracts	9,680	11,207
Total contract liabilities	9,680	12,163
Less current portion	(1,728)	(2,483)
Non-current portion	$ 7,952	$ 9,680

Pengrowth assumed a natural gas fixed price sales contract and firm transportation commitments in conjunction with certain acquisitions. The fair values of these contracts were estimated on the date of acquisition and the amount recorded is reduced as the contracts settle.

8. CONVERTIBLE DEBENTURES

The 6.5 percent convertible unsecured subordinated debentures (the Debentures) were scheduled to mature on December 31, 2010 with interest paid semi-annually in arrears on June 30 and December 31 of each year. Each $1,000 principal amount of Debentures was convertible at the option of the holder at any time into Pengrowth trust units at a conversion price of $25.54 per unit.

The Debentures have been classified as debt, net of the fair value of the conversion feature which is included in equity at the date they were assumed in a business combination. The fair value of the conversion feature was calculated using an option pricing model. The debt premium is amortized into interest expense over the term of the Debentures. As of December 31, 2009 and 2008, Debentures with a face value of $74.7 million were outstanding.

As at December 31, 2009, the Convertible Debentures were presented on the Consolidated Balance Sheet as a non-current liability, pursuant to specific accounting guidance that permits the disclosure of a current obligation as non-current when the obligation was refinanced on a long term basis subsequent to the balance sheet date but prior to the issuance of the financial statements. Pengrowth redeemed the Convertible Debentures on January 14, 2010 using incremental borrowings from the revolving credit facility (see Note 23).

9. LONG TERM DEBT

	2009	2008
U.S. dollar denominated senior unsecured notes:		
150 million at 4.93 percent due April 2010	$ 157,546	$ 182,180
50 million at 5.47 percent due April 2013	52,417	60,727
400 million at 6.35 percent due July 2017	418,530	485,080
265 million at 6.98 percent due August 2018	277,138	321,231
	$ 905,631	$ 1,049,218
U.K. Pound Sterling denominated 50 million unsecured notes at 5.46 percent due December 2015	84,514	88,285
Canadian dollar 15 million senior unsecured notes at 6.61 percent due August 2018	15,000	15,000
Canadian dollar revolving credit facility borrowings	60,000	372,000
Total long term debt	$ 1,065,145	$ 1,524,503
Current portion of long term debt due April 2010	(157,546)	
Non-current portion of long term debt	$ 907,599	$ 1,524,503

Credit Facilities

Pengrowth has a committed unsecured $1.2 billion syndicated extendible revolving credit facility. The facility is covenant based and matures on June 15, 2011. Pengrowth has the option to extend this facility annually subject to lender approval or repay the entire balance upon maturity. The revolving facility was reduced by drawings of $60 million and outstanding letters of credit in the amount of approximately $18 million at December 31, 2009.

Pengrowth also maintains a $50 million demand operating facility. This facility was reduced by drawings of $11 million and outstanding letters of credit of approximately $5 million at December 31, 2009. All borrowings under this facility are included in bank indebtedness on the balance sheet.

Various borrowing options exist under both facilities including prime rate advances and bankers acceptances. All drawings are subject to a stamping fee which varies between 60 basis points (bps) and 115 bps depending on Pengrowth s consolidated senior debt to earnings before interest, taxes and non-cash items ratio.

Term Notes

On April 23, 2003, Pengrowth closed a U.S. $200 million private placement of senior unsecured notes. These notes were offered in two tranches of U.S. $150 million at 4.93 percent due April 2010 and U.S. $50 million at 5.47 percent due in April 2013.

On December 1, 2005, Pengrowth closed a U.K. Pound Sterling 50 million private placement of senior unsecured notes due December 2015. In a series of related risk management transactions, Pengrowth fixed the U.K. Pound Sterling to Canadian dollar exchange rate for all the semi-annual interest payments and the principal repayments at maturity. The notes have an effective rate of 5.49 percent after the risk management transactions.

On July 26, 2007, Pengrowth closed a U.S. $400 million private placement of senior unsecured notes. These notes bear interest at 6.35 percent and are due July 2017.

On August 21, 2008, Pengrowth closed a U.S. $265 million private placement of senior unsecured notes. These notes bear interest at 6.98 percent and are due August 2018.

On August 21, 2008, Pengrowth closed a Cdn $15 million private placement of senior unsecured notes. The notes bear interest at 6.61 percent and are due August 2018.

All series of term notes contain substantially similar financial maintenance covenants and interest is paid semi-annually. Costs incurred in connection with each term note issuance were deducted from the carrying amount of the debt and are amortized to net income using the effective interest method over the expected term of the notes.

As of December 31, 2009, an unrealized cumulative foreign exchange gain of $77.6 million (December 31, 2008 loss of $66.9 million) has been recognized on the U.S. dollar term notes since the date of issuance. As of December 31, 2009, an unrealized cumulative foreign exchange gain of $29.2 million (December 31, 2008 $25.4 million) has been recognized on the U.K. Pound Sterling denominated term notes since Pengrowth ceased to designate existing foreign exchange swaps as a hedge on January 1, 2007.

The five year schedule of long term debt repayment based on current maturity dates and assuming the revolving credit facility is not renewed is as follows: 2010 $157.7 million, 2011 $60 million, 2012 nil, 2013 $52.6 million, 2014 nil.

10. ASSET RETIREMENT OBLIGATIONS

The ARO were estimated by management based on Pengrowth s working interest in wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred, considering various factors including the annual reserves evaluation of Pengrowth s properties from the independent reserve evaluators. Pengrowth has estimated the net present value of its ARO to be $289 million as at December 31, 2009 (December 31, 2008 $344 million), based on a total escalated future liability of $2,016 million (December 31, 2008 $2,283 million). These costs are expected to be made over 50 years with the majority of the costs incurred between 2039 and 2056. Pengrowth s credit adjusted risk free rate of eight percent (2008 eight percent) and an inflation rate of two percent (2008 two percent) were used to calculate the net present value of the ARO.

The following reconciles Pengrowth s ARO:

52

	2009	2008
ARO, beginning of year	$ 344,345	$ 352,171
Increase (decrease) in liabilities during the year related to:		
Acquisitions	365	3,414
Dispositions	(2,195)	(5,663)
Additions	3,146	3,618
Revisions (1)	(66,500)	(4,555)
Accretion expense	27,677	28,051
Liabilities settled in the year	(18,042)	(32,691)
ARO, end of year	$ 288,796	$ 344,345

(1) A corresponding adjustment was made to the related asset.

The following summarizes Pengrowth s expenditures on ARO for 2009 and 2008:

Expenditures on ARO	2009	2008
Expenditures on ARO not covered by the trust funds	$ 17,484	$ 32,403
Expenditures on ARO covered by the trust funds (Note 5)	558	288
	$ 18,042	$ 32,691

11. INCOME TAXES

The Trust is a mutual fund trust as defined under the Income Tax Act (Canada). All taxable income earned by the Trust has been allocated to unitholders and such allocations are deducted for income tax purposes.

On June 22, 2007, the Canadian government implemented a new tax (the SIFT tax) on publicly traded income trusts and limited partnerships (Bill C-52 Budget Implementation Act). For existing income trusts and limited partnerships, the SIFT tax will be effective in 2011 unless certain rules related to undue expansion are not adhered to. As such, the Trust would not be subject to the new measures until the 2011 taxation year provided the Trust continues to meet certain requirements.

	2009	2008
(Loss) income before taxes	$ (58,092)	$ 323,925
Combined federal and provincial tax rate	29.50%	29.50%
Expected income tax (reduction) expense	(17,137)	95,558
Net income of the Trust (1)	(98,851)	(200,998)
Foreign exchange (gain) loss (2)	(21,956)	24,783
Effect of change in corporate tax rate	5,968	430
Other including stock based compensation (3)	(4,799)	1,859
Change in valuation allowance	(6,170)	6,443
Future income tax reduction	$ (142,945)	$ (71,925)

(1) Relates to estimated distributions of taxable income at the trust level where there is no tax liability to Pengrowth as it is the responsibility of the unitholder (2009 - $334.4 million X 29.56%, 2008 - $618.4 million X 32.50%).

(2) Reflects the 50% non-taxable portion of foreign exchange (gains) losses which are treated as capital transactions and only 50% taxable (2009 - $148.8 million gain X 50% X 29.56%, 2008 - $164.6 million loss X 50% X 30.11%).
(3) Primarily expenses that are non-deductible for tax purposes and other adjustments.

The future income tax rates in 2009 and 2008 were approximately 25 percent and were applied to the temporary differences compared to the federal and provincial statutory rate of approximately 29 percent for the 2009 and 2008 income tax years.

The net future income tax liability is composed of:

Table of Contents

	2009	2008
Future income tax assets:		
Asset retirement obligation	$ 68,890	$ 84,090
Non-capital losses	135,263	117,987
Unrealized commodity loss	7,312	
Capital losses	273	
Foreign exchange loss		6,443
Contract liabilities	2,551	3,292
	214,289	211,812
Less: Valuation allowance	(273)	(6,443)
	214,016	205,369
Future income tax liabilities:		
Property, plant and equipment and other assets	(382,285)(1)	(491,170)
Unrealized commodity gain		(42,481)
Foreign exchange gain	(12,402)	
Net future tax liability	$ (180,671)	$ (328,282)

(1) Reduction from 2008 primarily due to depletion for accounting purposes exceeding tax pools claimed in the year.
In calculating its future income tax liability in 2009, Pengrowth included $539.4 million (2008 $462.8 million) related to non-capital losses available for carryforward to reduce taxable income in future years. These losses expire between 2010 and 2029.

12. TRUST UNITS

Pengrowth is authorized to issue an unlimited number of trust units.
Total Trust Units:

	2009		2008	
Trust Units Issued	Number of Trust Units	Amount	Number of Trust Units	Amount
Balance, beginning of year	256,075,997	$ 4,588,587	246,846,420	$ 4,432,737
Issued on redemption of Deferred Entitlement Units (DEUs) (non-cash)	416,043	5,741	238,633	2,484
Issued for cash on exercise of trust unit options and rights	299,684	1,918	290,363	4,274
Issued for cash under Distribution Reinvestment Plan (DRIP)	3,026,166	26,319	3,727,256	59,423
Issued for the Accrete business combination			4,973,325	89,253
Issued for cash under At The Market (ATM) Plan	1,169,900	10,723		
Issued for cash on equity issue	28,847,000	300,009		
Trust unit rights incentive plan (non-cash exercised)		346		614
Issue costs net of tax		(12,698)		(198)

Balance, end of year	289,834,790	$ 4,920,945	256,075,997	$ 4,588,587

During 2009, 1,000 Class A trust units (2008 no Class A trust units) were converted to consolidated trust units. As at December 31, 2009, 888 Class A trust units (December 31, 2008 1,888 units) remain outstanding. All other trust units outstanding are consolidated trust units.

Redemption Rights

All trust units are redeemable by Computershare, as trustee, on demand by a unitholder, when properly endorsed for transfer and when accompanied by a duly completed and properly executed notice requesting redemption, at a redemption price equal to the lesser of: (i) 95 percent of the average closing price of the trust units on the market designated by the Board of Directors for the ten days after the trust units are surrendered for redemption and (ii) the closing price of the trust units on such market on the date the trust units are surrendered for redemption. The redemption right permits unitholders to redeem trust units for maximum proceeds of $25,000 in any calendar month provided that such limitation may be waived at the discretion of the Board of Directors. Redemptions in excess of the cash limit must be satisfied by way of a distribution in specie of a pro rata share of Royalty Units and other assets, excluding facilities, pipelines or other assets associated with oil and natural gas production, which are held by the Trust at the time the trust units are to be redeemed. The price of trust units as applicable, for redemption purposes is based upon the closing trading price of the trust units irrespective of whether the units being redeemed are trust units or Class A trust units.

Distribution Reinvestment Plan

Unitholders are eligible to participate in the Distribution Reinvestment Plan (DRIP). DRIP entitles the unitholder to reinvest cash distributions in additional units of the Trust. The trust units under the plan are issued from treasury at a five percent discount to the weighted average closing price of trust units traded on the TSX for the 20 trading days preceding a distribution payment date.

At The Market Distribution

On July 10, 2009, Pengrowth amended the Equity Distribution Program which permits Pengrowth to distribute up to 25,000,000 Trust Units from time to time at prevailing market rates through either the New York or Toronto Stock Exchanges. Trust unit sales, if any, pursuant to the Equity Distribution Program will be made in transactions that are deemed to be at-the-market distributions , including sales made directly on the New York Stock Exchange or the Toronto Stock Exchange. The volume and timing of sales, if any, will be at Pengrowth s discretion. Regulatory approval permitting the at-the-market distribution was allowed to expire in January 2010 and may be reinstated at any time. In 2009, approximately 1.2 million trust units were issued under the Equity Distribution Program (2008 nil).

Contributed Surplus

	2009	2008
Balance, beginning of year	$ 16,579	$ 9,679
Trust unit rights incentive plan (non-cash expensed)	2,953	2,348
Deferred entitlement trust units (non-cash expensed)	5,172	7,650
Trust unit rights incentive plan (non-cash exercised)	(346)	(614)
Deferred entitlement trust units (non-cash exercised)	(5,741)	(2,484)
Balance, end of year	$ 18,617	$ 16,579

13. TRUST UNIT BASED COMPENSATION PLANS

Up to ten percent of the issued and outstanding trust units, to a maximum of 24 million trust units, may be reserved for DEUs, rights and option grants, in aggregate, subject to a maximum of 5.5 million DEUs available for issuance pursuant to the long term incentive program. As at December 31, 2009, there were 4.6 million trust units available for DEUs and rights grants, which includes 2.6 million DEUs available for issuance (December 31, 2008 8.1 million and 3.6 million respectively).

Long Term Incentive Program

The DEUs issued under the plan vest and are converted to trust units in the third year from the date of grant and will receive deemed distributions prior to the vesting date in the form of additional DEUs. However, the number of DEUs actually issued to each participant at the end of the three year vesting period will be subject to a performance test which compares Pengrowth s three year average total return to the three year average total return of a peer group of other energy trusts such that upon vesting, the number of trust units issued from treasury may range from zero to one and one-half times the total of the number of DEUs granted plus accrued DEUs through the deemed reinvestment of distributions.

Compensation expense related to DEUs is based on the fair value of the DEUs at the date of grant. The fair value of the DEUs is determined at the date of grant using the closing trust unit price and an estimate of the performance factor. The amount of compensation expense is reduced by the estimated forfeitures at the date of grant, which has been estimated at 25 percent for officers and employees. The number of trust units awarded at the end of the vesting period is subject to certain performance conditions. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions.

Table of Contents

Compensation expense is recognized in income over the vesting period with a corresponding increase or decrease to contributed surplus. Upon the issuance of trust units at the end of the vesting period, trust unitholders capital is increased and contributed surplus is decreased by the amount of compensation expense related to the DEUs. The trust units are issued from treasury upon vesting.

Pengrowth recorded compensation expense of $5.2 million in 2009 (2008 $7.6 million) related to the DEUs based on the weighted average grant date fair value of $6.55 per DEU (2008 $17.88 per DEU). As at December 31, 2009, the amount of compensation expense to be recognized over the remaining vesting period was $6.6 million (December 31, 2008 $8.7 million) or $4.34 per DEU (2008 $8.72 per DEU), subject to the determination of the performance multiplier. The unrecognized compensation cost will be expensed to net income over the remaining weighted average vesting period of 1.6 years (2008 1.3 years).

	2009			2008		
DEUs	Number of DEUs		Weighted average price	Number of DEUs		Weighted average price
Outstanding, beginning of year	1,270,750	$	19.38	868,042	$	20.13
Granted	1,174,601	$	6.55	578,833	$	17.88
Forfeited	(120,637)	$	12.63	(158,532)	$	19.54
Exercised	(297,184)	$	20.57	(202,020)	$	18.51
Deemed DRIP [1]	263,939	$	14.05	184,427	$	19.70
Outstanding, end of year	2,291,469	$	12.38	1,270,750	$	19.38

(1) Weighted average deemed DRIP price is based on the average of the original grant prices.

Trust Unit Rights Incentive Plan

Pengrowth has a Trust Unit Rights Incentive Plan, pursuant to which rights to acquire trust units may be granted to the directors, officers, employees, and special consultants. Pengrowth has not granted Trust Unit Rights to directors since 2006. Under the Rights Incentive Plan, distributions per trust unit to unitholders in a calendar quarter which represent a return of more than 2.5 percent of the net book value of property, plant and equipment at the beginning of such calendar quarter may result, at the discretion of the holder, in a reduction in the exercise price. Total price reductions calculated for 2009 were $0.03 per trust unit right (2008 $1.01 per trust unit right). One third of the rights granted under the Rights Incentive Plan vest on the grant date, one third on the first anniversary date of the grant and the remaining on the second anniversary. The rights have an expiry date of five years from the date of grant.

As at December 31, 2009, rights to purchase 5,455,598 trust units were outstanding (December 31, 2008 3,292,622) that expire at various dates to December 18, 2014.

	2009		2008	
Trust Unit Rights	Number of rights	Weighted average price	Number of rights	Weighted average price

Outstanding, beginning of year	3,292,622	$	16.78	2,250,056	$	17.39
Granted [1]	2,958,378	$	6.63	1,703,892	$	17.96
Forfeited	(495,718)	$	12.25	(397,469)	$	17.49
Exercised	(299,684)	$	6.40	(263,857)	$	14.55
Outstanding, end of year	5,455,598	$	12.23	3,292,622	$	16.78
Exercisable, end of year	3,087,494	$	14.95	1,950,375	$	16.52

[1] Weighted average exercise price of rights granted are based on the exercise price at the date of grant.

The following table summarizes information about trust unit rights outstanding and exercisable at December 31, 2009:

56

Table of Contents

	Rights Outstanding			Rights Exercisable	
Range of exercise prices	Number outstanding	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable	Weighted average exercise price
$6.00 to $8.99	2,122,141	4.2	$ 6.12	522,804	$ 6.13
$9.00 to $12.99	620,943	3.3	$ 10.32	321,898	$ 11.15
$13.00 to $18.99	2,341,899	2.8	$ 17.13	1,881,380	$ 17.19
$19.00 to $22.99	370,615	1.3	$ 19.41	361,412	$ 19.41
$6.00 to $22.99	5,455,598	3.3	$ 12.23	3,087,494	$ 14.95

Compensation expense associated with the trust unit rights granted during 2009 was based on the estimated fair value of $1.13 per trust unit right (2008 $1.68). The fair value of trust unit rights granted in the period was estimated at 17 percent of the exercise price at the date of grant using a binomial lattice option pricing model with the following assumptions: risk-free rate of 1.7 percent, volatility of 43 percent, expected distribution yield of 20 percent per trust unit and reductions in the exercise price over the life of the trust unit rights. The amount of compensation expense is reduced by the estimated forfeitures at the date of grant which has been estimated at five percent for directors and officers and ten percent for employees.

Compensation expense related to the trust unit rights in 2009 was $3.0 million (2008 $2.3 million). As at December 31, 2009, the amount of compensation expense to be recognized over the remaining vesting period was $1.4 million (December 31, 2008 $1.2 million), or $0.23 per trust unit right (December 31, 2008 $0.37 per trust unit right). The unrecognized compensation cost will be expensed to net income over the weighted average remaining vesting period of 1.1 years (2008 1.1 years). The trust units are issued from treasury upon vesting and exercise.

Trust Unit Option Plan

Pengrowth terminated the trust unit option plan on June 28, 2009. No new grants have been issued under the plan since November 2002. As at December 31, 2009, no trust unit options were outstanding (December 31, 2008 1,700 were outstanding with a weighted average exercise price of $14.95).

Employee Savings Plans

Pengrowth has savings plans whereby Pengrowth will match contributions by qualifying employees of one to 12 percent of their annual base salary, less any of Pengrowth s contributions to the Group Registered Retirement Savings Plan (Group RRSP), to purchase trust units in the open market. Participants in the Group RRSP can make contributions from one to 12 percent and Pengrowth will match contributions to a maximum of six percent of their annual basic salary. Pengrowth s share of contributions to the Trust Unit Purchase Plan and Group RRSP in 2009 were $4.6 million and $1.1 million, respectively (2008 $4.2 million and $1.0 million, respectively).

Trust Unit Margin Purchase Plan

On November 11, 2009 the Trust Unit Margin Purchase Plan was terminated. No new margin accounts were opened and no further purchases of Trust Units were made on margin subsequent to this date. Existing plan participants were not required to withdraw from the plan.

Pengrowth has provided a $1 million letter of credit to the investment dealer to guarantee amounts owing with respect to the plan (2008 $1 million). The amount of the letter of credit may fluctuate depending on the amounts financed pursuant to the plan. At December 31, 2009, 495,226 trust units (December 31, 2008 432,789) were deposited under the plan with a market value of $5 million (December 31, 2008 $4 million) and a corresponding margin loan of $3.9 million (December 31, 2008 $4.3 million).

14. DEFICIT

	2009	2008
Accumulated earnings	$ 2,156,041	$ 2,071,188
Accumulated distributions declared	(4,300,562)	(4,012,709)
	$ (2,144,521)	$ (1,941,521)

Pengrowth historically under its Royalty and Trust Indentures and NPI agreement distributed to unitholders a significant portion of its cash flow from operations. Cash flow from operations typically exceeds net income or loss as a result of non-cash expenses such as unrealized gains (losses) on commodity contracts, unrealized foreign exchange gains (losses), depletion, depreciation and accretion. These non-cash expenses result in a deficit being recorded despite Pengrowth distributing less than its cash flow from operations.

Distributions Paid

Actual cash distributions paid in 2009 were $334 million (2008 $675 million). Distributions declared have been determined in accordance with the Trust Indenture. Distributions are declared payable in the following month after the distributions were earned. The amount of cash not distributed to unitholders is at the discretion of the Board of Directors.

15. FOREIGN EXCHANGE (GAIN) LOSS

	2009	2008
Unrealized foreign exchange (gain) loss on translation of U.S. dollar denominated debt	$ (144,455)	$ 181,856
Unrealized foreign exchange gain on translation of U.K. pound sterling denominated debt	(3,840)	(9,230)
	(148,295)	172,626
Unrealized (gain) loss on foreign exchange risk management contracts	(938)	24,533
	(149,233)	197,159
Realized foreign exchange gain	(489)	(7,987)
	$ (149,722)	$ 189,172

16. OTHER CASH FLOW DISCLOSURES

Change in Non-Cash Operating Working Capital

Cash provided by (used for):	2009	2008
Accounts receivable	$ 15,284	$ 9,452
Accounts payable and accrued liabilities	(48,529)	23,536
Due from Pengrowth Management Limited	623	108
Net working capital on acquisition		(5,548)
	$ (32,622)	$ 27,548

Change in Non-Cash Investing Working Capital

Cash provided by (used for):	2009	2008
Accounts receivable	$ (495)	$
Accounts payable and capital accruals	(26,962)	(1,799)
	$ (27,457)	$ (1,799)

Cash Interest Payments

58

	2009	2008
Interest on long-term debt	$ 85,566	$ 66,267

17. RELATED PARTY TRANSACTIONS

The management agreement with Pengrowth Management Limited (the Manager) expired on June 30, 2009. The Manager provided certain services pursuant to the management agreement. In 2009 Pengrowth was charged $2.8 million for management fees (2008 $6.9 million). In addition, Pengrowth was charged $2.1 million (2008 $1.1 million) for reimbursement of general and administrative expenses incurred by the Manager. Amounts charged by the Manager were pursuant to a management agreement approved by the unitholders. The law firm controlled by the former Corporate Secretary of the Corporation charged $0.8 million in 2009 (2008 $1.0 million) for legal and advisory services provided to Pengrowth. The fees charged by this law firm have been recorded at the exchange amount which management believes approximates the fair value. Amounts receivable or payable from or to the related parties are unsecured, non-interest bearing and have no set terms of repayment. During 2009, the former Corporate Secretary was granted 44,304 trust unit rights and 8,861 DEUs (2008 23,670 trust unit rights and 3,945 DEUs).

A senior officer of the Corporation is a member of the Board of Directors of Monterey, a company that Pengrowth owns approximately 20 percent of the outstanding common shares.

18. AMOUNTS PER TRUST UNIT

The following reconciles the weighted average number of trust units used in the basic and diluted net income per unit calculations:

	2009	2008
Weighted average number of trust units basic	264,121,262	250,182,464
Dilutive effect of trust unit options, trust unit rights and DEUs	1,779,172	333,531
Weighted average number of trust units diluted	265,900,434	250,515,995

In 2009, 5.8 million trust units (2008 6.2 million) from trust unit options, rights, DEUs and the convertible debentures were excluded from the diluted net income per unit calculation as their effect is anti-dilutive.

19. CAPITAL DISCLOSURES

Pengrowth defines its capital as trust unitholders equity, long term debt, bank indebtedness, convertible debentures and working capital.

Pengrowth s goal over longer periods is to maintain or modestly grow production and reserves on a debt adjusted per unit basis. Pengrowth seeks to retain sufficient flexibility with its capital to take advantage of acquisition opportunities that may arise.

Pengrowth must comply with certain financial debt covenants. Compliance with these financial covenants is closely monitored by management as part of Pengrowth s overall capital management objectives. The covenants are based on specific definitions prescribed in the debt agreements and are different between the credit facility and the term notes. Throughout the period, Pengrowth was in compliance with all financial covenants.

Pengrowth s ability to issue trust units and convertible debt is subject to external restrictions as a result of the Specified Investment Flow-Through Entities Legislation (the SIFT tax). Pengrowth is grandfathered for the SIFT tax, however Pengrowth may lose the benefit of the grandfathering period, which ends December 31, 2010, if Pengrowth exceeds the limits on the issuance of new trust units and convertible debt that constitute normal growth during the grandfathering period (subject to certain exceptions). As of December 31, 2009 Pengrowth may issue $3.9 billion of equity in total for 2010 under the safe harbour provisions. The normal growth restriction on trust unit issuance is monitored by management as part of the overall

capital management objectives. Pengrowth is in compliance with the normal growth restrictions.
Management monitors capital using non-GAAP financial metrics, primarily total debt to the trailing twelve months earnings before interest, taxes, depletion, depreciation, amortization, accretion, and other non-cash items (EBITDA) and Total Debt to Total Capitalization. Pengrowth seeks to manage the ratio of total debt to trailing EBITDA and Total Debt to Total Capitalization ratio with the objective of being able to finance its growth strategy while maintaining sufficient flexibility under the debt covenants. However, there may be instances where it would be acceptable for total debt to trailing EBITDA to temporarily fall outside of the normal targets set by management such as in financing an acquisition to take advantage of growth opportunities. This would be a strategic decision recommended by management and approved by the Board of Directors with steps taken in the subsequent period to restore Pengrowth s capital structure based on its capital management objectives.
In order to maintain its financial condition or adjust its capital structure, Pengrowth may issue new debt, refinance existing debt, issue additional equity, adjust the level of distributions paid to unitholders, adjust the level of capital spending or dispose of non-core assets to reduce debt levels. To maintain its financial flexibility and in response to a decline in commodity prices, Pengrowth reduced its monthly distributions in 2008 and 2009 from $0.225 per trust unit to $0.07 per trust unit.
Pengrowth s objectives, policies and processes for managing capital have remained substantially consistent from the prior year. Management believes that current total debt to trailing EBITDA and total debt to total capitalization are within reasonable limits.
The following is a summary of Pengrowth s capital structure, excluding unitholders equity:

As at:		December 31, 2009		December 31, 2008
Term credit facilities	$	60,000	$	372,000
Senior unsecured notes[(1)]		847,599		1,152,503
Working capital deficiency		217,007		70,159
Convertible debentures		74,828		74,915
Total debt including convertible debentures	$	1,199,434	$	1,669,577

(1) Non-current portion of long term debt

20. FINANCIAL INSTRUMENTS

Pengrowth s financial instruments are composed of accounts receivable, accounts payable and accrued liabilities, fair value of risk management assets and liabilities, remediation trust funds, investments in other entities, distributions payable to unitholders, bank indebtedness, long term debt and convertible debentures.
Details of Pengrowth s significant accounting policies for recognition and measurement of financial instruments are disclosed in Note 2.

RISK MANAGEMENT OVERVIEW

Pengrowth has exposure to certain market risks related to volatility in commodity prices, interest rates and foreign exchange rates. Derivative instruments are used to manage exposure to these risks. Pengrowth s policy is not to utilize financial instruments for trading or speculative purposes.
The Board of Directors and management have overall responsibility for the establishment of risk management strategies and objectives. Pengrowth s risk management policies are established to identify the risks faced by Pengrowth, to set appropriate risk limits, and to monitor adherence to risk limits. Risk management policies are reviewed regularly to reflect changes in market conditions and Pengrowth s activities.

MARKET RISK

Market risk is the risk that the fair value, or future cash flows of financial assets and liabilities, will fluctuate due to movements in market prices. Market risk is composed of commodity price risk, foreign currency risk, interest rate risk and equity price risk.

Table of Contents

Commodity Price Risk

Pengrowth is exposed to commodity price risk as prices for oil and gas products fluctuate in response to many factors including local and global supply and demand, weather patterns, pipeline transportation and political stability and economic factors. Commodity price fluctuations are an inherent part of the oil and gas business. While Pengrowth does not consider it prudent to entirely eliminate this risk, it does mitigate some of the exposure to commodity price risk to protect the return on acquisitions and provide a level of stability to operating cash flow which enables Pengrowth to fund distributions and its capital development program. Pengrowth utilizes financial contracts to fix the commodity price associated with a portion of its future production. The use of forward and futures contracts are governed by formal policies and is subject to limits established by the Board of Directors. The Board of Directors and management may re-evaluate these limits as needed in response to specific events such as market activity, additional leverage, acquisitions or other transactions where Pengrowth s capital structure may be subject to more risk from commodity prices.

As at December 31, 2009, Pengrowth had fixed the price applicable to future production as follows:

Crude Oil:

Remaining term	Volume (bbl/d)	Reference Point	Price per bbl
Financial:			
Jan 1, 2010 - Dec 31, 2010	12,500	WTI (1)	$82.09 Cdn
Jan 1, 2011 - Dec 31, 2011	500	WTI (1)	$82.44 Cdn

(1) Associated Cdn $/U.S. $ foreign exchange rate has been fixed

Natural Gas:

Remaining term	Volume (mmbtu/d)	Reference Point	Price per mmbtu
Financial:			
Jan 1, 2010 - Dec 31, 2010	97,151	AECO	$6.10 Cdn
Jan 1, 2010 - Dec 31, 2010	5,000	Chicago MI (1)	$6.78 Cdn
Jan 1, 2011 - Dec 31, 2011	33,174	AECO	$5.77 Cdn
Jan 1, 2011 - Dec 31, 2011	5,000	Chicago MI (1)	$6.78 Cdn

(1) Associated Cdn $/U.S. $ foreign exchange rate has been fixed

Power:

Remaining term	Volume (mwh)	Reference Point	Price per mwh

Financial:			
Jan 1, 2010 - Dec 31, 2010	20	AESO	$47.66 Cdn

The above commodity risk management contracts are classified as held for trading and are recorded on the balance sheet at fair value.

The fair value of the commodity risk management contracts are recorded as current and non-current assets and liabilities on a contract by contract basis. The change in the fair value of the commodity risk management contracts during the period is recognized as an unrealized gain or loss on the statement of income as follows:

Commodity Risk Management Contracts	2009	2008
Current portion of unrealized risk management assets	$ 14,001	$ 122,841
Non-current portion of unrealized risk management assets		41,851
Current portion of unrealized risk management liabilities	(16,661)	
Non-current portion of unrealized risk management liabilities	(6,374)	
Total unrealized risk management (liabilities) assets at year end	$ (9,034)	$ 164,692

	2009	2008
Total unrealized risk management (liabilities) assets at year end	$ (9,034)	$ 164,692
Less: Unrealized risk management assets (liabilities) at beginning of year	164,692	(85,207)
Unrealized (loss) gain on risk management contracts for the year	$ (173,726)	$ 249,899

Commodity Price Sensitivity

Table of Contents

Each Cdn $1 per barrel change in future oil prices would result in approximately Cdn $4.7 million pre-tax change in the unrealized gain (loss) on commodity risk management contracts as at December 31, 2009 (December 31, 2008 $7.3 million). Similarly, each Cdn $0.25 per mcf change in future natural gas prices would result in approximately Cdn $12.8 million pre-tax change in the unrealized gain (loss) on commodity risk management contracts (December 31, 2008 $8.3 million). Each Cdn $1 per MWh change in future power prices would result in approximately Cdn $0.2 million pre-tax change in the unrealized gain (loss) on commodity risk management contracts.

As of close December 31, 2009, the AECO spot price gas price was approximately $5.81/mcf (December 31, 2008 $6.35/mcf), the WTI prompt month price was US $79.36 per barrel (December 31, 2008 $44.60 per barrel), and the daily average power pool spot price was approximately Cdn $43.79/MWh.

Foreign Exchange Risk

Pengrowth is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices. Pengrowth has mitigated some of this exchange risk by entering into fixed Canadian dollar crude oil and natural gas price swaps as outlined in the commodity price risk section above.

Pengrowth is exposed to foreign currency fluctuation on the U.S. dollar denominated notes for both interest and principal payments. Pengrowth has not entered into any contracts to mitigate the foreign exchange risk associated with the U.S. dollar denominated term notes as the U.S. dollar denominated interest payments partially offset U.S. dollar denominated revenues.

Pengrowth entered into foreign exchange risk management contracts in conjunction with issuing U.K. Pounds Sterling 50 million ten year term notes which fixed the Canadian dollar to U.K. Pound Sterling exchange rate on the interest and principal of the U.K. Pound Sterling denominated debt at approximately 0.4976 U.K. Pounds Sterling per Canadian dollar. The estimated fair value of the foreign exchange risk management contracts at December 31, 2009 was approximately $17.8 million.

The foreign exchange risk management contracts are classified as held for trading and are recorded on the balance sheet at fair value. The fair value of the foreign exchange risk management contracts are allocated to current and non-current assets and liabilities on a contract by contract basis. The change in the fair value of the foreign exchange risk management contracts during the period is recognized as an unrealized gain or loss on the statement of income as follows:

Foreign Exchange Risk Management Contracts	2009	2008
Current portion of unrealized risk management liabilities	$ (894)	$ (2,706)
Non-current portion of unrealized risk management liabilities	(16,895)	(16,021)
Total unrealized risk management liabilities at year end	$ (17,789)	$ (18,727)

	2009	2008
Total unrealized risk management liabilities at year end	$ (17,789)	$ (18,727)
Less: Unrealized risk management (liabilities) assets at beginning of year	(18,727)	5,806
Unrealized gain (loss) on risk management contracts for the year	$ 938	$ (24,533)

Foreign Exchange Rate Sensitivity

The following summarizes the sensitivity on a pre-tax basis of a change in the foreign exchange rate on unrealized foreign exchange gains (losses) related to the translation of the foreign denominated term debt and on unrealized gains (losses) related to the change in the fair value of the foreign exchange risk management contracts, holding all other variables constant:

Foreign Exchange Sensitivity as at December 31, 2009	Cdn $0.01 Exchange Rate Change	
	Cdn - U.S.	Cdn - U.K.
Unrealized foreign exchange gain or loss on foreign denominated debt	$ 8,650	$ 500
Unrealized foreign exchange risk management gain or loss		572

Foreign Exchange Sensitivity as at December 31, 2008	Cdn $0.01 Exchange Rate Change Cdn - U.S.	 Cdn - U.K.
Unrealized foreign exchange gain or loss on foreign denominated debt	$ 8,650	$ 500
Unrealized foreign exchange risk management gain or loss		577

Interest Rate Risk

Pengrowth is exposed to interest rate risk on the Canadian dollar revolving credit facility as the interest is based on floating interest rates. Pengrowth has mitigated some of its exposure to interest rate risk by issuing fixed rate term notes.

Interest Rate Sensitivity

As at December 31, 2009, Pengrowth has approximately $1.1 billion of long term debt (December 31, 2008 $1.5 billion) of which $60 million (December 31, 2008 $372 million) is based on floating interest rates. A one percent increase in interest rates would increase pre-tax interest expense by approximately $0.6 million for 2009 (2008 $3.7 million).

Equity Price Risk

Pengrowth has exposure to equity price risk on investments in an exchange traded bond fund related to a portion of the remediation trust fund and on its investment in a publicly traded entity. Pengrowth s exposure to equity price risk is not significant.

FAIR VALUE

The fair value of accounts receivable, accounts payable and accrued liabilities, bank indebtedness, and distributions payable approximate their carrying amount due to the short-term nature of those instruments. The fair value of the Canadian dollar revolving credit facility is equal to its carrying amount as the facility bears interest at floating rates and credit spreads within the facility are indicative of market rates.

The following tables provide fair value measurement information for financial assets and liabilities as of December 31, 2009 and 2008.

As at December 31, 2009	Carrying Amount	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Financial Assets					
Remediation trust funds	$ 34,837	$ 34,821	$ 34,821	$	$
Fair value of risk management contracts	14,001	14,001		14,001	
Other Assets investment in public company	1,151	1,151	1,151		
Financial Liabilities					
U.S. dollar denominated senior unsecured notes	905,631	963,136		963,136	
Cdn dollar senior unsecured notes	15,000	15,164		15,164	

U.K. Pound Sterling denominated unsecured notes	84,514	89,724		89,724	
Convertible debentures	74,828	76,423	76,423		
Fair value of risk management contracts	40,824	40,824		40,824	

			Fair Value Measurements Using:		
As at December 31, 2008	Carrying Amount	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Financial Assets					
Remediation trust funds	$ 27,122	$ 26,948	$ 26,948	$	$
Fair value of risk management contracts	164,692	164,692		164,692	
Other Assets investment in public company	624	624	624		
Financial Liabilities					
U.S. dollar denominated senior unsecured notes	1,049,218	1,213,723		1,213,723	
Cdn dollar senior unsecured notes	15,000	16,075		16,075	
U.K. Pound Sterling denominated unsecured notes	88,285	95,495		95,495	
Convertible debentures	74,915	68,014	68,014		
Fair value of risk management contracts	18,727	18,727		18,727	

Level 1 Fair Value Measurements

Remediation trust funds investments in the SOEP remediation trust fund are recorded at fair value which is based on the quoted market value of the underlying investments in the fund at the balance sheet date. The fair value of the Judy Creek remediation trust fund is based on the quoted market value of the underlying investments in the fund at the balance sheet date.

Other Assets investment in public company the fair value of the investment in the public company has been determined using the closing trading price of the public company s common shares on the balance sheet date.
Convertible debentures the fair value of the convertible debentures has been determined using the closing trading price of the debentures on the balance sheet date.

Level 2 Fair Value Measurements

Risk management contracts the fair value of the risk management contracts are estimated based on the mark-to-market method of accounting, using publicly quoted market prices or, in their absence, third-party market indications and forecasts priced on the last trading day of the applicable period.

Foreign and Canadian dollar denominated debt the fair value of the foreign and Canadian dollar denominated term notes is determined based on the risk free interest rate on government debt instruments of similar maturities, adjusted for estimated credit risk, industry risk and market risk premiums.

CREDIT RISK

Credit risk is the risk of financial loss to Pengrowth if a counterparty to a financial instrument fails to meet its contractual obligations. A significant portion of Pengrowth s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Continued uncertainty in the credit markets may restrict the ability of Pengrowth s normal business counterparties to meet their obligations to Pengrowth. Additional credit risk could exist where little or none previously existed. However, given the current state of global credit markets, oil and gas companies including Pengrowth may be exposed to an increased risk of a general decline in counterparty credit worthiness. Pengrowth manages its credit risk by performing a credit review on each marketing counterparty and following a credit practice that limits transactions according to the counterparty s credit rating as assessed by Pengrowth. In addition, Pengrowth may require letters of credit or parental guarantees from certain counterparties to mitigate some of the credit risk associated with the amounts owing by the counterparty. The use of financial swap agreements involves a degree of credit risk that Pengrowth manages through its credit policies which are designed to limit eligible counterparties to those with investment grade credit ratings or better. The carrying value of accounts receivable and risk management assets represents Pengrowth s maximum credit exposure.

Pengrowth sells a significant portion of its oil and gas to a limited number of counterparties. Pengrowth has two counterparties that individually account for more than ten percent of monthly revenues. Both counterparties are large, well-established companies supported by investment grade credit ratings.

Pengrowth considers amounts over 90 days as past due. As at December 31, 2009 and 2008, the amount of accounts receivable that were past due was not significant. Pengrowth has not recorded a significant allowance for doubtful accounts as no significant impairment issues exist at December 31, 2009 and 2008. Pengrowth s objectives, processes and policies for managing credit risk have not changed from the previous year.

LIQUIDITY RISK

Liquidity risk is the risk that Pengrowth will not be able to meet its financial obligations as they fall due. Pengrowth s approach to managing liquidity is to ensure, as much as possible, that it will always have sufficient liquidity to meet its liabilities when due, under normal and stressed conditions. Management closely monitors cash flow requirements to ensure that it has sufficient cash on demand or borrowing capacity to meet operational and financial obligations over the next three years. Pengrowth maintains a committed $1.2 billion term credit facility with a syndicate of seven Canadian and four foreign banks and a $50 million demand operating line of credit. Pengrowth s long term notes and bank credit facilities are unsecured and equally ranked.

All of Pengrowth s financial liabilities are current and due within one year, except as follows:

Table of Contents

As at December 31, 2009	Carrying Amount	Contractual Cash Flows	Within 1 year	1-2 years	2-5 years	More than 5 years
Cdn dollar revolving credit facility[1]	$ 60,000	$ 60,892	$ 613	$ 60,279	$	$
Cdn dollar senior unsecured notes[1]	15,000	23,571	992	992	2,977	18,610
U.S. dollar denominated senior unsecured notes[1]	748,085	1,131,180	49,009	49,009	194,858	838,304
U.K. Pound Sterling denominated unsecured notes[1]	84,514	112,384	4,637	4,637	13,923	89,187
Convertible debentures[1] [2]	74,828	79,599		79,599		
Remediation trust fund payments		12,500	250	250	750	11,250
Commodity risk management contracts	6,374	6,517		6,517		
Foreign exchange risk management contracts	16,895	180	30	30	90	30

(1) Contractual cash flows include future interest payments calculated at period end exchange rates and interest rates

(2) Convertible debentures were redeemed on January 14, 2010 using proceeds from the revolving credit facility (Note 23). The repayment of the convertible debentures has been shown in the above table as due in 1-2 years with the revolving credit facility.

Carrying Contractual

As at December 31, 2008	Amount	Cash Flows	Within 1 year	1-2 years	2-5 years	More than 5 years
Cdn dollar revolving credit facility[(1)]	$ 372,000	$ 393,919	$ 8,630	$ 8,630	$ 376,659	$
Cdn dollar senior unsecured notes[(1)]	15,000	24,556	992	992	2,975	19,597
U.S. dollar denominated senior unsecured notes[(1)]	1,049,218	1,570,918	65,805	65,805	414,482	1,024,826
U.K. Pound Sterling denominated unsecured notes[(1)]	88,285	122,286	4,847	4,847	14,541	98,051
Convertible debentures[(1)]	74,915	84,457	4,858	79,599		
Remediation trust fund payments		12,500	250	250	750	11,250
Foreign exchange risk management contracts	18,727	210	30	30	90	60

(1) Contractual cash flows include future interest payments calculated at period end exchange rates and interest rates

21. COMMITMENTS

	2010	2011	2012	2013	2014	Thereafter	Total
Operating leases	$ 12,935	$ 12,695	$ 12,489	$ 12,359	$ 12,141	$ 35,383	$ 98,002

Operating leases include office rent and vehicle leases.

22. CONTINGENCIES

Pengrowth is sometimes named as a defendant in litigation. The nature of these claims is usually related to settlement of normal operational issues and labour issues. The outcome of such claims against Pengrowth is not determinable at this time; however, their ultimate resolution is not expected to have a materially adverse effect on Pengrowth as a whole.

23. SUBSEQUENT EVENTS

On January 14, 2010, Pengrowth redeemed all of the outstanding Convertible Unsecured Subordinated Debentures. The cash redemption amount of approximately $76.8 million, including accrued interest to the redemption date, was funded with incremental borrowings from the revolving credit facility.

On February 17, 2010, Pengrowth completed a disposition of certain royalty interests for proceeds, net of adjustments, of approximately $39 million.

On February 19, 2010, Monterey issued additional equity in a public offering through which Pengrowth purchased 952,500 shares of Monterey for approximately $4.0 million and continues to own approximately 20 percent of the outstanding common shares subsequent to the share purchase.

Table of Contents

24. RECONCILIATION OF FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The significant differences between Canadian generally accepted accounting principles (Canadian GAAP) which, in most respects, conforms to United States generally accepted accounting principles (U.S. GAAP), as they apply to Pengrowth, are as follows:

(a) As required quarterly under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of future income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at ten percent (based on the average of the prices on the first day of each month for the year ended December 31, 2009, and prior to December 31, 2009 based on commodity prices in effect on the date of the impairment test), plus the lower of cost and fair value of unproven properties. At December 31, 2009, the application of the full cost ceiling test under U.S. GAAP did not result in a write-down of capitalized costs. At December 31, 2008, the application of the full cost ceiling test under U.S. GAAP resulted in a before-tax write-down of capitalized costs of $1,529.9 million (total write-downs prior to December 31, 2008 $492.6 million).

Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion will differ in subsequent years. In addition, under U.S. GAAP depletion is calculated based on constant dollar reserves as opposed to escalated dollar reserves required under Canadian GAAP. As such, the depletion rate under U.S. GAAP differs from Canadian GAAP. The effect of ceiling test impairments and a different depletion rate under U.S. GAAP has reduced the 2009 depletion charge by $189.4 million (2008 $24.7 million). Depletion on a per unit of production under U.S. GAAP was $13.53 per BOE (2008 $20.21).

(b) Other comprehensive income under U.S. GAAP differs from that presented under Canadian GAAP as a result of designating a cash flow hedge at different dates under U.S. GAAP as compared to Canadian GAAP. Effective January 1, 2007, Pengrowth ceased to designate its foreign exchange swaps as a cash flow hedge of the U.K. term debt. The amount deferred in accumulated other comprehensive income pertaining to this hedging relationship when the hedge was de-designated of $2.4 million is being amortized to income over the life of the foreign exchange swap under U.S. GAAP.

(c) Under U.S. GAAP, securities which are subject to mandatory redemption requirements or whose redemption is outside the control of the issuer must be classified outside of permanent equity and are to be recorded at their redemption amount at each balance sheet date with changes in redemption amount being charged to the deficit. The amount charged to the deficit representing the change in the redemption amount between balance sheet dates for the periods presented must also be disclosed. Furthermore, the balance sheet disclosure of trust unitholders capital would not be permitted and trust unitholders capital would be reclassified to mezzanine equity, a liability.

The trust units are redeemable at the option of the holder at a redemption price equal to the lesser of 95% of the average closing price of the trust units for the 10 trading days after the trust units have been surrendered for redemption and the closing price on the date the trust units have been surrendered for redemption. However, the total amount payable by the Trust in cash in any one calendar month is limited to a maximum of $25,000. Redemptions in excess of the cash limit must be satisfied by way of a distribution in specie of a pro rata share of royalty units and other assets, excluding facilities, pipelines or other assets associated with oil and gas production, which are held by the Trust at the time the trust units are to be redeemed. As a result of the significant limitation on the cash amount payable by the Trust in respect of redemptions, and that any royalty units issued would have similar characteristics of the trust units and be convertible back into trust units, the trust units have not been classified as redeemable equity for the purposes of U.S. GAAP.

(d) Under U.S. GAAP, an entity that is subject to income tax in multiple jurisdictions is required to disclose income tax expense in each jurisdiction. Pengrowth is subject to tax at the federal and provincial level. The portion of the income tax reduction at the federal level for the year ended December 31, 2009 is $42.0 million (2008 $319.5 million). The portion of income tax reduction at the provincial level is $23.4 million (2008 $173.8 million).

(e) Additional disclosures required under U.S. GAAP with respect to Pengrowth s equity incentive plans is provided below.

The intrinsic value of the DEUs, trust unit rights and trust unit options exercised was as follows:

	2009		2008	
	Number Exercised	Intrinsic Value	Number Exercised	Intrinsic Value
DEUs	297,184	$3,121	202,020	$4,511
Trust Unit Rights	299,684	867	263,857	1,271
Trust Unit Options			26,506	64
Total	596,868	$3,988	492,383	$5,846

The following table summarizes information about trust unit options, trust unit rights and DEUs vested and expected to vest:

At December 31, 2009	Trust Unit Rights	DEUs
Number vested and expected to vest	5,218,787	1,570,348
Weighted average exercise price per unit (1)	$ 12.39	$
Aggregate intrinsic value (2)	$ 8,238	$ 15,939
Weighted average remaining life (years)	3.3	1.4

At December 31, 2008	Trust Units Options	Trust Unit Rights	DEUs
Number vested and expected to vest	1,700	3,158,397	1,117,550
Weighted average exercise price per unit (1)	$ 14.95	$ 16.76	$
Aggregate intrinsic value (2)	$	$	$ 10,449
Weighted average remaining life (years)	0.5	3.2	1.4

(1) No proceeds are received upon exercise of DEUs.

(2) Based on December 31 closing trust unit price.

The following table summarizes information about trust unit options and trust unit rights outstanding:

Table of Contents

At December 31, 2009	Trust Unit Rights	DEUs
Number exercisable	3,087,494	
Weighted average exercise price per unit [(2)]	$ 14.95	$
Aggregate intrinsic value [(3)]	$ 2,217	$
Weighted average remaining life (years)	2.7	

At December 31, 2008	Trust Units Options	Trust Unit Rights	DEUs
Number exercisable [(1)]	1,700	1,950,375	2,209
Weighted average exercise price per unit [(2)]	$ 14.95	$ 16.52	$
Aggregate intrinsic value [(3)]	$	$	$ 25
Weighted average remaining life (years)	0.5	2.7	

(1) DEUs exercisable at December 31, 2008 were granted to employees on long-term leave on the vesting date. DEUs will be exercised upon return from long-term leave or termination from the plan. No DEUs were exercisable at December 31, 2009.

(2) No proceeds are received upon exercise of DEUs.

(3) Based on December 31 closing price.

(f) Under Canadian GAAP, the convertible debentures are classified as debt with a portion, representing the estimated fair value of the conversion feature at the date of issue, being allocated to equity. In addition, under Canadian GAAP a non-cash interest expense or income representing the effective yield of the debt component is recorded in the consolidated statements of income with a corresponding credit or debit to the convertible debenture liability balance to accrete the balance to the principal due on maturity as a result of the portion allocated to equity.

Under U.S. GAAP, the convertible debentures, in their entirety, are classified as debt. The non-cash interest expense recorded under Canadian GAAP related to the equity portion of the debenture would not be recorded under U.S. GAAP.

(g) The following table summarizes the unrecognized tax benefits under U.S. GAAP:

	2009	2008
Balance, January 1	$ 21,239	$ 17,810
Additions (decreases) based on tax positions in the year	(1,260)	3,859
Decrease due to change in tax rates	(691)	(430)
Balance, December 31	$ 19,288	$ 21,239

The following table summarizes open taxation years at December 31, 2009 by jurisdiction:

Jurisdiction	Years
Federal	2004 - 2008
Alberta, British Columbia, Saskatchewan, and Nova Scotia	2004 - 2008

The 2004 tax examination by federal authorities is currently in progress.

Interest and penalties related to uncertain tax positions, which are included in income tax expense, were not material for the years ended December 31, 2009 and 2008.

Unrecognized tax benefits are classified as current or long-term liabilities under U.S. GAAP as opposed to future income tax liabilities. It is anticipated that no amount of the current or prior year unrecognized tax benefit will be realized in the next year. The unrecognized tax benefit, if recognized, would have a favourable impact on Pengrowth s effective income tax rate in future periods.

(h) Fair Value Measurements

The framework for measuring fair value when an entity is required to use a fair value measure for recognition or disclosure purposes under U.S. GAAP is consistent with the framework under Canadian GAAP, except that Canadian GAAP only requires disclosure of the fair value hierarchy for items normally measured at fair value. In addition, under Canadian GAAP the framework only applies to financial assets and liabilities measured at fair value as at December 31, 2009 while under U.S. GAAP the framework applies to all financial assets and liabilities and non-financial assets and liabilities measured at fair value or for which fair value is disclosed for December 31, 2009 and only for financial assets and liabilities as of December 31, 2008. Pengrowth s disclosure under Canadian GAAP includes assets and liabilities measured at fair value and for which fair value is disclosed, consistent with U.S. GAAP. Please see Note 20 to the audited annual financial statements for fair value disclosures as of December 31, 2009 and 2008.

(i) Under U.S. GAAP, unrealized gains or losses on commodity risk management would be included with oil and gas sales.

(j) Effective January 1, 2009, Pengrowth adopted new disclosure standards under U.S. GAAP with respect to derivatives and hedging. These new disclosure standards are similar to Canadian GAAP (see note 20). The following are additional disclosures required under U.S. GAAP with respect to Pengrowth s derivatives.

Pengrowth has not designated any outstanding risk management contracts as hedges for accounting purposes and therefore records these contracts on the balance sheet at their fair value and recognizes changes in fair value on the statement of income (loss) as unrealized commodity risk management contracts. The effect on cash flows will be recognized separately only upon realization of the contracts, which could vary significantly from the unrealized amount recorded due to timing and prices when each contract is settled. The use of commodity contracts involves a degree of credit risk that Pengrowth manages through its credit policies which are designed to limit eligible counterparties to those with investment grade credit ratings or better. The total of all risk management assets is $38.2 million (2008 $164.8 million). The total of all risk management liabilities is $65.0 million (2008 $18.8 million). Under Canadian and U.S. GAAP, the risk management assets and risk management liabilities are netted by individual counterparty, thus the maximum amount of potential loss due to credit risk is the carrying amount of the risk management assets recorded on the balance sheet. There are no contingent features of these contracts related to Pengrowth s credit risk.

(k) Other accounting policy changes under U.S. GAAP:

(i) In June 2009, the Financial Accounting Standards Board (FASB) developed the Accounting Standards Codification (codification) that consolidates all authoritative accounting guidance into a single source that uses a simple, consistent structure for organizing accounting topics. The codification does not change U.S. GAAP but reorganizes it into a consistent structure for ease of research and cross-reference. All other non-grandfathered non-SEC accounting literature not included in the codification will become non-authoritative. The codification became effective on September 15, 2009 and implementation had no effect on Pengrowth s financial position, results of operations or cash flow.

Table of Contents

(ii) Effective January 1, 2009, Pengrowth adopted new U.S. GAAP standards with respect to business combinations which require an acquirer to be identified for all business combinations and applies the same method of accounting for business combinations (the acquisition method) to all transactions. In addition, transaction costs associated with acquisitions are required to be expensed. The revised statement is effective to business combinations in years beginning on or after December 31, 2008. There were no business combinations that occurred during 2009 therefore adoption of these standards did not create any Canadian to U.S. GAAP differences.

(iii) On December 31, 2009, Pengrowth adopted new rules and regulations issued by the SEC with respect to reserves and reporting of reserves. The new rules impacted the calculation of the U.S. GAAP ceiling test. Effective December 31, 2009, the ceiling test is based on the proven reserves discounted at ten percent using the average of the commodity prices on the first day of each month in the year rather than the year end commodity prices.

Table of Contents

Consolidated Statements of Income

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

(Stated in thousands of Canadian Dollars, except per trust unit amounts)

	Year ended December 31, 2009	Year ended December 31, 2008
Net income for the year, as reported	$ 84,853	$ 395,850
Adjustments:		
Depletion and depreciation (a)	189,371	24,735
Ceiling test write-down (a)		(1,529,935)
Amortization of discontinued hedge (b)	272	272
Non-cash interest on convertible debentures (f)	40	40
Future tax adjustments	(77,553)	421,369
Net income (loss) U.S. GAAP	$ 196,983	$ (687,669)
Other comprehensive income (loss):		
Amortization of discontinued hedge (b)	(272)	(272)
Comprehensive income (loss) U.S. GAAP	$ 196,711	$ (687,941)
Net Income (Loss) per trust unit U.S. GAAP		
Basic	$ 0.74	$ (2.75)
Diluted	$ 0.74	$ (2.75)

71

Table of Contents

Consolidated Balance Sheets

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

(Stated in thousands of Canadian Dollars)

As at December 31, 2009	As Reported	Increase (Decrease)	U. S. GAAP
Assets			
Property, plant and equipment (a)	$3,789,369	$(1,562,502)	$2,226,867
Future income taxes (d)(g)		251,473	251,473
		$(1,311,029)	
Liabilities			
Convertible debentures	$ 74,828	$ 40	$ 74,868
Future income taxes (d)(g)	180,671	(180,671)	
Other long term liabilities (g)		19,288	19,288
Unitholders equity:			
Accumulated other comprehensive income	$	$ 1,630	$ 1,630
Trust unitholders equity (c)	2,795,201	(1,151,316)	1,643,885
		$(1,311,029)	

As at December 31, 2008	As Reported	Increase (Decrease)	U. S. GAAP
Assets			
Property, plant and equipment (a)	$4,251,381	$(1,751,873)	$2,499,508
Future income taxes (d)		183,366	183,366
		$(1,568,507)	
Liabilities			
Convertible debentures	$ 74,915	$ 80	$ 74,995
Future income taxes (d)	328,282	(328,282)	
Other long term liabilities (d)		21,239	21,239
Unitholders equity:			
Accumulated other comprehensive income	$	$ 1,902	$ 1,902
Trust unitholders equity (c)	2,663,805	(1,263,446)	1,400,359

$(1,568,507)

Table of Contents

Additional disclosures required under U.S. GAAP

The components of accounts receivable are as follows:

	As at December 31, 2009	As at December 31, 2008
Trade	$ 159,309	$ 159,274
Prepaid	23,033	37,857
	$ 182,342	$ 197,131

The components of accounts payable and accrued liabilities are as follows:

	As at December 31, 2009	As at December 31, 2008
Accounts payable	$ 50,998	$ 94,799
Accrued liabilities	134,339	166,029
	$ 185,337	$ 260,828

Table of Contents

APPENDIX D
SUPPLEMENTAL UNAUDITED DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES REQUIRED UNDER UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Table of Contents

SUPPLEMENTAL INFORMATION OIL AND GAS PRODUCING ACTIVITIES
(unaudited)

The following are supplementary oil and gas disclosures required under U. S. generally accepted accounting principles. All amounts in thousands, unless otherwise noted:

OIL AND GAS RESERVES

Users of this information should be aware that the process of estimating quantities of proved and proved developed crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume royalty rates in existence at the time the estimates were made, the Trust s estimate of future production volumes and new SEC Modernization of Oil and Gas Reporting rules, using the average of the first-day-of-the-month prices during the 12 month period before the end of the year (prior to December 31, 2009, pricing was based on the year end price). This same 12 month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The unaudited supplemental information on oil and gas exploration and production activities for 2009 has been presented in accordance with the new reserve estimation and disclosure rules, which may not be applied retrospectively. The 2008 data are presented in accordance with FASB oil and gas disclosure requirements effective during that period. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Trust s share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2009 no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Table of Contents

The impact of Pengrowth s equity accounted investments on the supplemental oil and gas disclosures is not material.

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred in oil and gas producing activities for the years ended December 31 are as follows:

	2009	**2008**
Property acquisition costs		
Proved	$ 24,653	$ 182,401
Unproved	11,002	
Exploration costs	13,915	22,012
Development costs	123,104	365,304
Injectants costs	13,298	21,009
	$ 185,972	$ 590,726

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Development and exploration costs include the costs for drilling and equipping development and exploratory wells and constructing facilities to extract, treat and gather and store oil and gas and additions to asset retirement obligations.

Injectants (mostly ethane and methane) are used in miscible flood programs to stimulate incremental oil recovery. The cost of injectants purchased from third parties for miscible flood projects is deferred and amortized over the period of expected future economic benefit which is estimated to be 24 months.

Pengrowth capitalizes a portion of general and administrative costs associated with exploration and development activities. Prior to 2009, transaction costs directly attributable to successful business combinations are also capitalized. In 2009, transaction costs are expensed under U.S. accounting standards.

Approximately $67.6 million (2008 $45.4 million) of costs to acquire and evaluate unproven properties has been excluded from depletion.

Table of Contents

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation, depletion and amortization, including impairments, relating to the Trust s oil and gas exploration, development and producing activities at December 31 consist of:

	2009	2008
Oil and gas properties	$ 7,211,347	$ 7,079,703
Less accumulated depletion, depreciation and amortization	(5,027,476)	(4,635,531)
Net capitalized costs	$ 2,183,871	$ 2,444,172
Unproved oil and gas properties	$ 420,354	$ 484,426
Proven oil and gas properties	1,763,517	1,959,746
Net capitalized costs	$ 2,183,871	$ 2,444,172

Table of Contents

OIL AND GAS RESERVE INFORMATION

All of the Trust s proved oil, natural gas liquids, and natural gas reserves are located in Canada, in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. The Trust s proved developed and undeveloped reserves after deductions of royalties are summarized below:

Net Proved Developed and Undeveloped Reserves After Royalties

	Crude Oil and NGL s MMbbls	Natural Gas Bcf
End of year 2007	**111.5**	**528.7**
Revisions of previous estimates (including infill drilling & improved recovery)	3.6	40.3
Purchase of reserves in place	2.6	16.1
Sale of reserves in place		(1.0)
Discoveries and extensions	1.3	12.3
Production	(12.3)	(71.5)
End of year 2008	**106.7**	**524.9**
Revisions of previous estimates (including infill drilling & improved recovery)	0.4	(36.6)
Purchase of reserves in place	0.8	1.1
Sale of reserves in place	(0.5)	(7.8)
Discoveries and extensions	1.3	6.7
Production	(11.2)	(72.9)
End of year 2009	**97.5**	**415.4**
Net Proved Developed Reserves After Royalty		
End of year 2007	93.0	474.9
End of year 2008	87.9	474.4
End of year 2009	81.7	394.0

Notes:

1. Net after royalty reserves are the Trust s lessor royalty, overriding royalty, and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Crown royalties are

subject to change by legislation or regulation and vary depending on production rates, selling prices and potentially timing of initial production.

2. Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and the average of the commodity prices on the first day of each month for the year ended December 31, 2009. Prior to December 31, 2009 reserves are based on the commodity prices in effect on the last day of the year.

3. Proved oil and gas reserves are

the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

4. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

Table of Contents

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following information is based on crude oil and natural gas reserve and production volumes estimated by the independent engineering consultants of the Trust. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Trust or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Trust s reserves. The future cash flows presented below are based on cost rates, and statutory income tax rates in existence as of the date of the projections and the average of commodity prices in effect on the first day of each month for the year ended December 31, 2009. Prior to December 31, 2009 future net cash flows were based on commodity prices in effect on the last day of the year. It is expected that revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2009 was based on the following average of the first-day-of-the-month benchmark prices for the 12 month period before the end of the year: Edmonton par crude oil price of $63.59/bbl and AECO natural gas price of $3.84/MMBtu. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2008 was based on the following year end benchmark prices: Edmonton par crude oil price of $44.27/bbl and AECO natural gas price of $6.22/MMBtu.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND GAS RESERVES

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Trust s crude oil and natural gas reserves at December 31, for the years presented.

	2009	**2008**
Future cash inflows	$ 8,561	$ 8,843
Future costs		
Future production and development costs	(5,164)	(5,409)
Future income taxes	(623)	(635)
Future net cash flows	2,774	2,799
Deduct: 10% annual discount factor	(1,039)	(1,012)
Standardized measure of discounted future net cash flows	$ 1,735	$ 1,787

Table of Contents

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND GAS RESERVES

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for the years presented.

	2009 $MM	2008 $MM
Future discounted net cash flow at beginning of year	1,787	3,690
Sales & transfer, net of production costs	(737)	(1,044)
Net change in sales & transfer prices	233	(2,406)
Development costs incurred during the period	199	362
Change in future development costs	(79)	(371)
Change due to extensions and discoveries	30	33
Change due to revisions (including infill drilling & improved recovery)	(36)	111
Accretion of discount	207	459
Sales of reserves in place	(19)	(4)
Purchase of reserves in place	12	56
Net change in income taxes	(18)	616
Changes in timing of future net cash flow and other	156	285
Future discounted net cash flow at end of year	1,735	1,787

Note:

1. The schedules above are calculated using year-end costs, statutory tax rates and proved oil and gas reserves and the average of the commodity prices on the first day of each month for the year ended December 31, 2009. Prior to December 31, 2009 the schedules are based on the commodity prices in effect on the last day

of the year. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

Table of Contents

APPENDIX E
PENGROWTH ENERGY TRUST CODE OF BUSINESS CONDUCT AND ETHICS
DATED NOVEMBER 11, 2009

Table of Contents

Pengrowth Energy Trust
CODE OF BUSINESS CONDUCT AND ETHICS

November 11, 2009

Table of Contents

TABLE OF CONTENTS

Application

Unless expressly provided herein to the contrary, this Code of Business Conduct and Ethics (the **Code**) applies to all directors, officers, employees, consultants and contractors (each, a, **Member**) of Pengrowth Corporation, Pengrowth Energy Trust and their respective subsidiaries and affiliates (collectively, referred to herein as **Pengrowth**).

Purpose

Pengrowth s reputation for honesty and integrity has been earned by maintaining the highest standards of business ethics in all our interactions with our co-workers, governments, local communities, shareholders, customers, suppliers, competitors and the public. The commitment of every Member to preserve and perpetuate the letter and spirit of this Code is essential to our continued success.

This Code affirms the policy of Pengrowth and is a guideline to:

- assure compliance with laws and regulations that govern the business activities of Pengrowth;
- maintain a corporate climate in which the integrity and dignity of each individual is valued;
- foster a standard of conduct that reflects positively on Pengrowth; and
- protect Pengrowth from unnecessary exposure to financial loss.

This Code does not specifically address every potential form of unacceptable conduct, and it is expected that Members will exercise good judgment in compliance with the principles set out in this Code. Each Member has a duty to avoid any circumstance that would violate the letter or spirit of this Code. Unscrupulous dealings, non-compliance with this Code or the law or other dishonest or unethical business practices are forbidden and may result in disciplinary action, including termination from employment or termination of contractual relations.

It is important that Pengrowth be made aware of circumstances that may indicate possible violations of law or this Code. Pengrowth and applicable law prohibit any form of retaliation for raising concerns or reporting possible misconduct in good faith or for assisting in the investigation of possible misconduct. Any violations of this Code must be promptly reported to an appropriate person as outlined in Appendix A . Any Member may submit a complaint regarding a suspected violation of the Code without fear of dismissal or retaliation.

Policy

Pengrowth and all of its Members will adhere to the highest ethical standards in all our business activities. Any situation, decision or response should first consider what is right and how it reflects on Pengrowth. Although the various matters described in this Code do not cover the full spectrum of employee and contractor activities, they are indicative of the type of behaviour expected from employees and contractors in all circumstances.

Table of Contents

Members are expected to comply with all aspects of this Code.

If a director or officer has any question of appropriateness in a particular situation, areas of conflict or disagreement with any aspect of this policy, the matter should be discussed with the President and Chief Executive Officer, Chief Financial Officer, or Board Chairman of Pengrowth Corporation.

If an employee has any question of appropriateness in a particular situation, areas of conflict or disagreement with any aspect of this policy, the matter should be discussed with the employee s manager. It is recognized that there may be situations in which it is impractical or inappropriate for an employee to bring the matter to his or her manager. In these instances, employees should seek the advice of the Director, Human Resources or Pengrowth s legal counsel.

If a consultant or contractor has any question of appropriateness in a particular situation, areas of conflict or disagreement with any aspect of this policy, the matter should be discussed with the consultant s or contractor s supervisor.

Compliance with the Law

A concern for what is right underlies all business decisions. An issuer may be held liable for the wrongful actions of its directors, officers, employees, consultants or contractors. Accordingly, each Member must ensure that his or her dealings and actions on behalf of Pengrowth comply with the spirit and intent of all relevant legislation and regulations including those set by a self regulatory body or professional organization. Particular attention is directed to the laws and regulations relating to discrimination, privacy, securities, labour, safety and the environment.

In addition to the laws imposed by statute, the law also imposes a duty upon a company to honour agreements, whether in writing or not, and to act reasonably and in a manner that will not cause harm to others. Members must diligently ensure that their conduct is not and cannot be interpreted as being a contravention of laws governing the affairs of Pengrowth in any jurisdiction where it carries on business.

Ignorance of the law will not usually excuse a party who contravenes a law. Members are responsible to keep informed of laws which may affect those affairs of Pengrowth which are under his or her control.

Whenever a Member is in doubt about the application or interpretation of any legal requirement or has questions about whether particular circumstances may involve illegal conduct, the individual should immediately seek the advice of his or her manager or consult Pengrowth s legal counsel.

Pengrowth is subject to legislation in Canada, the United States and other jurisdictions that prohibits corrupt practices in dealing with foreign governments. These laws make it an offence to make or offer a payment, gift or other benefit to a foreign public official in order to induce favourable business treatment, such as obtaining or retaining business or some other advantage in the course of business. Violation of this legislation may result in substantial penalties to Pengrowth and to individuals. Foreign public officials include all people who perform public duties or functions for a foreign state. This can include anyone acting in an official capacity or under a delegation of authority from the government to carry out government ownership or control, such as national oil companies, regardless of whether the government in question has majority ownership or control.

Pengrowth, as well as each Member, must take all responsible steps to ensure that the requirements of this legislation are strictly met. No payments, gifts or other benefits are to be given, directly or indirectly, to foreign public officials, political parties or political candidates for the purpose of influencing government decisions in Pengrowth s favour or for securing other improper advantages. Furthermore, no such payments are to be made to agents or other third parties in circumstances where it is likely that part or all of the payment will be passed on to a foreign public official, political party or political candidate.

There are certain types of payments to foreign public officials that are allowed under both the Canadian and U.S. legislation called facilitation or facilitating payments. These are small payments or tips requested in the context of having routine administrative actions performed by foreign public officials. Members should be aware that such payments are permissible only under very limited circumstances. Advice should be sought from Pengrowth s legal counsel with respect to the amount and advisability of making a facilitation payment. Moreover, we must ensure that any such payments are properly recorded in accordance with Pengrowth s accounting procedures.

Health, Safety and the Environment

Pengrowth is committed to safe and healthful working conditions for all Members and third parties, and to conducting its activities in an environmentally responsible manner consistent with the principles of sustainable development. Members are expected to read and to understand Pengrowth s Environmental and Safety Policies and Procedures and participate fully in this effort by improving operations to avoid injury or sickness to persons, and damage to property and the environment and by giving due regard to all applicable safety standards, regulatory requirements, technical and conventional standards and restraints.

All conditions, situations or accidents which give rise to health, safety or environmental concerns must be immediately reported to the Manager, Safety and Training or the Manager, Environment.

Pengrowth authorizes each of its Members to take any emergency actions that are necessary or desirable to minimize any critical health, safety or environmental problems provided those actions are consistent with Pengrowth s philosophy and practices regarding health, safety and environmental protection.

Public Reporting

Full, fair, accurate, timely and understandable disclosure in the reports and other documents that Pengrowth files with, or submits to, the securities commissions and in its other public communications is critical for Pengrowth to maintain its good reputation, to comply with its obligations under the securities laws and to meet the expectations of its securityholders and other members of the investment community.

Table of Contents

Persons responsible for the preparation of such documents and reports and other public communications are to exercise the highest standard of care in their preparation in accordance with the following guidelines:

- all accounting records, and the reports produced from such records, must be in accordance with all applicable laws;
- all accounting records must fairly and accurately reflect the transactions or occurrences to which they relate;
- all accounting records must fairly and accurately reflect in reasonable detail Pengrowth s assets, liabilities, revenues and expenses;
- no accounting records should contain any false or intentionally misleading entries;
- no transactions should be intentionally misclassified as to accounts, departments or accounting periods;
- all transactions must be supported by accurate documentation in reasonable detail and recorded in the proper account and in the proper accounting period;
- no information should be concealed from the internal auditors or the independent auditors; and
- compliance with Pengrowth s system of internal controls is required.

Conflict of Interest

Members must avoid interests or relationships where their personal interests may affect their judgement in acting in the best interests of Pengrowth. This requires that each Member act in such a manner that his or her conduct will bear the closest scrutiny should circumstances demand that it be examined.

Where a conflict of interest situation may exist or be perceived to exist, the Member may be put in a compromising position or his or her judgement may be questioned. Pengrowth wants to ensure that all Members are, and are perceived to be, free to act in the best interests of Pengrowth. Disclosure of areas of potential conflict of interest will allow appropriate steps to be taken to protect the individual from these situations.

Each director and officer who is a party to a material contract or proposed material contract with Pengrowth 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 proposed material contract with Pengrowth of which he has knowledge is required to disclose in writing to the Board Chairman the nature and extent of the director s or officer s interest. The Board Chairman shall make any such disclosure concerning himself to the President & CEO.

Officers, employees, consultants and contractors are required to disclose to the appropriate Vice President in writing all business, commercial or financial interests and activities which might reasonably be regarded as creating an actual or potential conflict with their duties of employment. Senior management will determine whether a conflict of interest does or could exist and, if necessary, advise the person of what steps should be taken. Directors are required to disclose to the chairman of the Corporate Governance Committee (or, in the case of the chairman of the Corporate Governance Committee, to another member of the Committee) all business, commercial or financial interests and activities which might reasonably be regarded as creating an actual or potential conflict with their duties as directors.

There are many situations which can be classified as conflicts of interest, but the following examples illustrate those that are most common.

Private Business

Unless otherwise consented to by his or her immediate superior, a Member, either directly or indirectly through his or her immediate family or by any other means, must not have a personal financial interest in, or place himself or herself in a position where he or she could derive a benefit or interest from, a business transaction with Pengrowth, which financial interest or benefit is of such a nature that it would reasonably be expected to create a conflict of interest for the Member.

This, however, does not prevent a Member and his or her family from having ownership in publicly traded shares or equity in companies which may do business with Pengrowth or prevent a consultant or contractor from providing his or her services to Pengrowth through a third party corporation.

Payments

It is Pengrowth s policy to deal fairly and lawfully with all customers, suppliers and independent contractors purchasing or furnishing goods or services. All goods and services shall be obtained on a competitive basis at the best value considering price, quality, reliability, availability and delivery.

Members shall not accept gratuities or favours of any sort having more than a nominal value from any person, organization or group that does, or is seeking to do, business with Pengrowth or any of its affiliates or from a competitor of Pengrowth or any of its affiliates. Members should neither seek nor accept gifts, payments, services, fees, trips or accommodations, special privileges of value or loans from any person, organization or group that does, or is seeking to do, business with Pengrowth or any of its affiliates (unless they are in the business of lending, and then only on conventional terms) or from a competitor of Pengrowth or any of its affiliates. Gifts of nominal value (advertising mementos, desk calendars or pens), acceptance of hospitality or entertainment (lunch, dinner or tickets to a local sporting event) and attendance at transaction closing celebrations are acceptable, provided that acceptance of such gifts, hospitality or entertainment and closing celebrations would not reasonably be expected to create a conflict of interest. Directors should report gifts of a questionable nature to the President & CEO or Board Chairman and officers, employees, consultants and contractors should report gifts of a questionable nature to their superior.

Except as contemplated herein, no Member shall offer or provide, either personally or on behalf of Pengrowth, any expensive gifts, excessive entertainment or payments of any amount of money to any supplier, customer, sub-contractor, or competitor of Pengrowth s, or to any public official or their representatives, nor pay to them, either directly or indirectly, any commissions or fees which are excessive in relation to the services rendered. Modest gifts, favours and entertainment may be furnished by Members whose duties permit them to do so, provided all of the following tests are met:

- Ø they are not in cash or securities and are of nominal value;
- Ø they do not contravene any law and are made as a matter of general and accepted practice or in accordance with corporate policy; and
- Ø if subsequently disclosed to the public, they would not in any way embarrass Pengrowth or their recipients.

It is acknowledged that, from time to time, Pengrowth holds investor conferences, the purpose of which is to educate investors and brokers about the oil and gas business generally and Pengrowth s business specifically. A portion of the costs incurred by attendees of the conferences is paid by Pengrowth.

Political Contributions

Any political contribution made on behalf of Pengrowth shall comply with the following requirements:

(a) any such contribution may only be made to a political party and not to an individual candidate for election to public office;

(b) any such contribution requires the approval of the Chief Executive Officer; and

(c) any such contribution must be within the approved operating budget of Pengrowth.

Contributions are deemed to include money, anything of value (e.g., loans, services or the use of Pengrowth facilities or assets) and time spent by employees during normal work hours away from work responsibilities. Individual Members are free to make political contributions in their personal capacity.

Involvement with Not-for-Profit Organizations

As a responsible community citizen, Pengrowth encourages and supports employee participation in charitable, educational, cultural, political and not-for-profit organizations. Employees are reminded that such participation should not be of a nature or extent that it adversely affects an employee s job performance or puts the employee in a conflict of interest position (see Conflict of Interest above).

Outside Employment

Pengrowth recognizes that some employees may, from time to time, hold additional part-time employment outside their employment relationship with Pengrowth. Employees are reminded that any such outside employments should not be of a nature or extent that it adversely affects the employee s job performance at Pengrowth or puts the employee in a conflict of interest position (see Conflict of Interest above).

All employees who hold management positions with Pengrowth shall obtain the approval of their supervisor before accepting any such outside employment.

Directorships

Any officer or employee shall obtain the approval of the President and Chief Executive Officer prior to accepting a position as a director of a for-profit company or business organization. The President and Chief Executive Officer shall obtain the approval of the Board of Directors prior to accepting a position as a director of a for-profit company or business organization. A director shall advise the Board Chairman prior to accepting a position as a director of a for-profit company or business organization.

Government Relations

Pengrowth, as a company offering services to a regulated industry and providing services which relate directly to regulations, must be especially sensitive to the interaction with public officials. All interaction and communications between Members and public officials are to be conducted in the highest ethical manner and must not compromise the integrity or reputation of any public official, Pengrowth, its affiliates or its employees.

Confidential Information

In the course of their work, Members may have access to information that is confidential, privileged, of value to competitors of Pengrowth or might be damaging to Pengrowth if improperly disclosed. Pengrowth respects privileged customer and employee related information, and therefore all Members must protect the confidentiality of such information.

The use or disclosure of confidential information must be for company purposes only and not for personal benefit or the benefit of others. This applies to disclosure of confidential information concerning Pengrowth or its business activities as well as information with respect to companies having business dealings with Pengrowth. To preserve confidentiality, disclosure and discussion of confidential information should be limited to those individuals who need to know the information.

Company Information

Members must guard against improper disclosure of information that may be of competitive value to Pengrowth. Pengrowth is in a competitive environment with other companies offering similar services. Certain records, reports, papers, devices, processes, plans, methods and apparatus of Pengrowth, including methods of doing business, strategies and information on costs, prices, sales, profits, markets and customers are the property of Pengrowth and are considered to be confidential and proprietary. Members must not reveal such confidential information without consent from their superiors.

Confidential information does not include information which is already in the public domain. Certain information may be released by Pengrowth (to comply with securities regulations, for example), however the release of such information is a decision of the Board of

Table of Contents

Directors and senior management. If there is any doubt as to what can or cannot be discussed outside of Pengrowth, Members should err on the side of discretion and not communicate any information. For more specific advice, your immediate manager or the Chief Financial Officer should be consulted.

These obligations regarding confidential information continue to apply to all Members following cessation of their employment or contractual relations with Pengrowth.

Inside Information

Certain information, which Pengrowth treats as confidential, may influence the price or trading of Pengrowth s trust units or other securities if it is disclosed to members of the public. Inside information would include information concerning major contracts, proposed acquisitions or mergers, and sales or earnings figures. Members shall not use such inside information for their own financial gain or for that of their associates.

Inside information is information which (1) has not been publicly released, (2) is intended for use solely by Pengrowth and not for personal use, or (3) is the type usually not disclosed by Pengrowth. All individuals who come into possession of material inside information, before it is publicly disclosed, are considered to be in a special relationship with Pengrowth for the purposes of securities laws. The husbands, wives, immediate families and those under control of insiders may also be regarded as being in a special relationship with Pengrowth. Included in the concept of insider trading is tipping or revealing inside information to individuals to enable such individuals to trade in a company s securities on the basis of undisclosed information.

Members are responsible for being familiar with and abiding by all laws, regulations and rules respecting insiders and insider trading . The various provincial securities legislation and business corporations acts impose certain liabilities upon every Member of Pengrowth, and any associate of such person, from using for their own benefit in connection with a trade in securities of Pengrowth any inside information, including that which, if generally known, might reasonably be expected to affect materially the market price of shares or other securities.

Pengrowth s policy parallels the law in that all Members who receive inside information about Pengrowth, its associates, affiliated companies and other companies in which it has an interest are in a position of trust and they must not trade in trust units or other securities on the basis of the information they possess, or otherwise make use of the information for their own benefit or advantage until at such time as the information has been fully disclosed and a reasonable period of time has passed for the information to be disseminated.

Pengrowth has adopted the following rule in respect of trading in securities of Pengrowth by its Members:

If you have knowledge of a material fact, pending change of fact, or material change related to the affairs of Pengrowth or any public issuer involved in a transaction with Pengrowth which is not generally known, no purchase or sale may be made until the knowledge has been made public. In addition, this knowledge must not be conveyed to any other person for the purpose of assisting that person in trading securities.

Table of Contents

For purposes of this rule, public issuer includes any issuer, whether a corporation or otherwise, whose securities are traded in a public market, whether on a stock exchange or over the counter . Material change or material fact is one which would be expected to have a significant effect on the market price or value of any securities of a public issuer. Pengrowth encourages Members to be securityholders in Pengrowth as one way to more tangibly link shareholder interests with those of the Members. However, Members possessing inside information are expected to show integrity and use proper judgement in timing their investments. If in doubt as to the propriety of actions, the Member should seek the advice of the Chief Financial Officer. Reference should be made to the *Policy on Trading in Securities* of Pengrowth Energy Trust.

Books of Account

Accurate, timely and reliable books of account and records are essential for effective management to ensure Pengrowth meets its business, legal and financial obligations. As a result, Members should ensure all transactions with which they are involved are authorized and executed in accordance with Pengrowth s procedures and that all transactions are completely and accurately accounted for and recorded.

Patents and Inventions

All inventions, discoveries and copyrights made by Members during or as a result of their employment or contractual relations with Pengrowth (where company time, equipment, resources or pertinent information has been used for personal gain) are the property of Pengrowth unless a written release is obtained from the Chief Executive Officer. Pengrowth and its Members honour the proprietary rights of others as expressed in patents, copyrights, trademarks and industrial design.

Community Relations

In its business, Pengrowth and its Members come in contact with many members of the business and investment community, including individuals, community groups, public officials and members of the media. Pengrowth strives to maintain its good reputation in the community and therefore needs to ensure that individuals speaking on behalf of Pengrowth recognize and deal with sensitive issues in an appropriate manner. Enquiries from members of the community related to matters of a sensitive nature should be directed to the Director of Government and Public Affairs or a member of senior management. The Director of Government and Public Affairs is then required to refer the matter to either the President and Chief Executive Officer or Chief Financial Officer whereby such senior officers will respond on behalf of Pengrowth. Reference should also be made to the *Corporate Disclosure Policy* of Pengrowth Energy Trust.

Table of Contents

Company Property and Opportunities

All Members are responsible for protecting Pengrowth s assets. Personal use of Pengrowth s property, including investment and other business opportunities, is not permitted without specific authorization.

Accounting and Financial Reporting

Pengrowth is committed to achieving compliance with all applicable securities laws and regulations, accounting standards, accounting controls and audit practices. Every Member is required to follow prescribed accounting and financial reporting procedures. All accounting records should accurately reflect and describe corporate transactions. The recording of such data must not be falsified or altered in any way to conceal or distort assets, liabilities, revenues, expenses or the nature of the activity.

Any suspected violation relating to accounting or financial reporting matters should be reported directly to Grant Thornton LLP pursuant to Appendix A to this document.

Employee Relations and Reporting

The continued success of Pengrowth is dependent on our employees, the work they perform, the ideas they contribute, and the ability, creativity and initiative they bring to the organization.

In working together, Pengrowth Members must ensure they treat each other with respect, dignity, honesty and fairness. Pengrowth is committed to providing opportunity for employees to be fully challenged, to develop their skills and abilities, and to reach their career goals.

In all matters related to the supervision and development of Members, including hiring, supervision, compensation, promotion and termination, no person will be discriminated against because of race, religious beliefs, gender (including sexual harassment and pregnancy), sexual orientation, physical or mental disability, ancestry or place of origin.

All Members are encouraged to report any behaviour of other Members which they reasonably believe is illegal or unethical to the Director, Human Resources. Any suspected violation of this Code should be reported directly to the chairman of the Corporate Governance Committee or to Grant Thornton LLP pursuant to Appendix A . Reporting can be done on an anonymous basis if the person wishes to do so. No adverse action will be taken against any individual for making a complaint or disclosing information in good faith, and any Member who retaliates in any way against an individual who in good faith reports any violation or suspected violation of this Code will be subject to disciplinary action.

Policies, Procedures and Internal Controls

It is essential that all Members follow established policies, procedures and internal controls. Any exception to established policies, procedures and internal controls is prohibited, unless appropriately authorized in advance by any two officers of Pengrowth who shall report all such

Table of Contents

approved exceptions to the Audit Committee. Exceptions to this Code are dealt with below under Exceptions and Changes .

Acknowledgement

It is essential that all Members of Pengrowth understand and adhere to this Code.

All Members of Pengrowth will be asked to acknowledge, in writing, their review of and agreement to be bound by this Code as a condition of their new or continuing employment or contractual relations, as the case may be. This acknowledgment must be made: (i) in the case of directors, upon election to the board of directors of the Corporation and annually thereafter; (ii) in the case of officers and employees, upon the commencement of employment and annually thereafter, (iii) in the case of consultants and contractors, upon commencement of this contractual relation and annually thereafter, and such acknowledgement may be provided in electronic format.

The form of certification attached as Appendix B is to be used by each Member to disclose any ***personal*** facts or dealings that are non-compliant with this Code.

Exceptions and Changes

In very limited circumstances, exceptions may be made by Pengrowth under this Code. Any exception proposed to be made under this Code shall be presented by the President and Chief Executive Officer to the Corporate Governance Committee for its approval.

Any change to this Code must be in writing, approved by the Board of Directors and signed by the President and Chief Executive Officer of Pengrowth Corporation and will be disclosed as required by applicable laws and regulations and listing standards.

Adopted by the Board of Directors of Pengrowth Corporation, as administrator of Pengrowth Energy Trust, on November 11, 2009.

Table of Contents

Appendix A
Complaint Procedures
For Accounting, Financial Reporting and Auditing Matters and
Violations of the Code of Business Conduct and Ethics

Any director, officer or employee of Pengrowth Corporation and its subsidiaries (collectively, referred to herein as Pengrowth) may submit a complaint regarding accounting or auditing matters to the management of Pengrowth without fear of dismissal or retaliation of any kind. Pengrowth is committed to achieving compliance with all applicable securities laws and regulations, accounting standards, accounting controls and audit practices. The Audit Committee of Pengrowth will oversee treatment of employee concerns in this area.

Any director, officer, employee, consultant or contractor of Pengrowth may submit a complaint regarding a suspected violation of the Code of Business Conduct and Ethics to the management of Pengrowth without fear of dismissal or retaliation. The Governance Committee of Pengrowth will oversee treatment of employee concerns in this area.

In order to facilitate the reporting of complaints, the Board of Directors of Pengrowth has established the following procedures for (i) the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, financial reporting or auditing matters (Accounting Matters); (ii) the receipt, retention and treatment of complaints regarding suspected violations of the Code of Business Conduct and Ethics (Conduct Matters); and (iii) the confidential, anonymous submission by directors, officers and employees of concerns regarding questionable Accounting Matters and Conduct Matters.

Receipt of Complaints

Directors, officers and employees with concerns regarding an Accounting Matter may report their concerns to the chairman of the Audit Committee.

Directors, officers, employees, consultants or contractors with concerns regarding a Conduct Matter may report their concerns to the chairman of the Corporate Governance Committee.

Directors, officers and employees may report concerns regarding an Accounting Matter or a Conduct Matter on a confidential or anonymous basis to Grant Thornton LLP, at 1-888-747-7171 or usecare@GrantThornton.ca.

A director, officer or employee who makes an anonymous submission must be sure to provide sufficient detail to identify the concern being raised. Because the submission is made anonymously, the Audit Committee or the Corporate Governance Committee, as the case may be, will be unable to follow up if there are additional questions. The complaint should, at a minimum, contain dates, places, persons involved and witnesses such that a reasonable investigation or assessment can be conducted.

Scope of Accounting Matters Covered by These Procedures

These procedures relate to director, officer or employee complaints relating to any questionable Accounting Matters, including, without limitation, the following:

Table of Contents

fraud or deliberate error in the preparation, evaluation, review or audit of any financial statement of Pengrowth;

fraud or deliberate error in the recording and maintaining of financial records of Pengrowth;

deficiencies in or non-compliance with Pengrowth s internal accounting controls;

misrepresentation or false statement to or by a director, officer, employee or external accountant regarding a matter contained in the financial records, financial reports or audit reports of Pengrowth; or

deviation from full and fair reporting of Pengrowth s financial condition.

Treatment of Complaints

Grant Thornton LLP shall inform (i) the chairman of the Audit Committee of all complaints and concerns provided to it in respect of Accounting Matters; and (ii) the chairman of the Corporate Governance Committee of all complaints provided to it in respect of Conduct Matters.

Upon receipt of a complaint or concern, the chairman of the Audit Committee or chairman of the Corporate Governance Committee, as the case may be, will (i) determine whether or not the complaint actually pertains to an Accounting Matter or a Conduct Matter and (ii) when possible, acknowledge receipt of the complaint to the sender.

Complaints relating to an Accounting Matter will be reviewed by the Audit Committee, outside legal counsel or such other persons as the Audit Committee determines to be appropriate. Complaints relating to a Conduct Matter will be reviewed by the Corporate Governance Committee, outside legal counsel and such and the persons as the Corporate Governance Committee determines to be appropriate. In any case, confidentiality will be maintained to the fullest extent possible, consistent with the need to conduct an adequate review.

Prompt and appropriate corrective action will be taken when and as warranted in the judgment of the Audit Committee or the Corporate Governance Committee, as the case may be.

Pengrowth will not discharge, demote, suspend, threaten, harass or in any manner discriminate against any individual in the terms and conditions of employment based upon any lawful actions of such individual with respect to reporting of complaints in good faith regarding any Accounting Matter or any Conduct Matter.

Pengrowth will regard the making of any deliberately false or malicious allegations by an employee as a serious offence which may result in recommendations to the Board of Directors or to senior management of Pengrowth for disciplinary action including dismissal for cause and, if warranted, legal proceedings.

Table of Contents

Reporting and Retention of Complaints and Investigations

The chairman of the Audit Committee and the chairman of the Corporate Governance Committee will maintain a log of all complaints, tracking their receipt, investigation and resolution and shall prepare a periodic summary report thereof for the Audit Committee or the Corporate Governance Committee, as the case may be.

Table of Contents

Appendix B

Awareness Statement on Code of Business Conduct and Ethics
To be completed by all directors, officers, employees, consultants and contractors
of Pengrowth Energy Trust and its subsidiaries (Pengrowth)

I have recently read the Code of Business Conduct and Ethics of Pengrowth (the Code), and I can certify that, except as specifically noted below:

1. I understand the content and consequences of contravening the Code and agree to abide by the Code.

2. I am in compliance with the Code.

3. All facts and dealings which I believe to be non-compliant with the Code have been communicated to the appropriate representative of Pengrowth and are detailed below.

4. (If applicable) After due inquiry and to my best knowledge and belief, no employee, consultant or contractor under my direct supervision is in violation of the Code.

5. I have and will continue to exercise my best efforts to assure full compliance with the Code by myself and (if applicable) all employees, consultants and contractors under my direct supervision.

Print or type name:

Signature:

Title and location:

Date:

Facts and dealings that I believe to be non-compliant with the Code

(Including potential conflict of interest situations)

1.

2.

(If required, provide additional details on separate sheet).

Page 15